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INCREASED AUTOMOBILE FUEL EFFICIENCY AND SYNTHETIC FUELS

Alternatives For Reducing Oil Imports

Background Paper #4

Environmental Issues of Synthetic Transportation Fuels From Coal

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Preface

This volume contains papers written for OTA to assist in preparation of the report *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports.* OTA does not endorse these papers. In several instances, the OTA report reaches somewhat different conclusions because of additional information which was obtained later. These papers, however, may prove valuable for readers needing more detailed or specific information than could be accommodated in the final assessment report, and are being made available for such purposes.

ENVIRONMENTAL ISSUES OF SYNTHETIC TRANSPORTATION FUELS FROM COAL

BACKGROUND REPORT

by

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PREFACE AND DISCLAIMER

This Background Report on Environmental Issues of Synthetic Transportation Fuels from Coal was prepared by an interdisciplinary team of the Science and Public Policy Program, University of Oklahoma, under contract with the Office of Technology Assessment, U.S. Congress. Martha W. Gilliland, Executive Director, Energy Policy Studies, Inc., Omaha, Nebraska, is a subcontractor contributing to the overall report. A summary and conclusions to this Background Report is available separately.

The analyses and conclusions presented in these reports do not necessarily reflect the views of the Office of Technology Assessment or the University of Oklahoma and are the sole responsibility of the authors.

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ENVIRONMENTAL ISSUES OF SYNTHETIC TRANSPORTATION FUELS FROM COAL

BACKGROUND REPORT

CHAPTER I

INTRODUCTION

A. OBJECTIVES AND APPROACH

The Energy Security Act of 1980 establishes the goal of developing a synthetic fuels industry with a capacity equivalent to 500,000 barrels per day (b/d) of crude oil by 1987 and two million barrels per day (MMb/d) by 1992. The U.S. Department of Energy and the emerging U.S. Synthetic Fuels Corporation and other executive branch agencies are reviewing the appropriate development of synthetic fuels in the emerging national energy plan under President Reagan's Administration (Oil and Gas Journal 1981). The environmental problems and issues associated with this development are crucial, as there is widespread public concern about the impacts of achieving substantial levels of synthetic fuel development. This background report provides an overview of the major environmental impacts and issues associated with producing synthetic fuels from coal. This background information was used in preparing the Summary Report, which provides a state-of-the-art review of the environmental problems, including:

(1) A comparison of environmental differences among competing synfuels technologies;

(2) An evaluation of the environmental differences between strict and lenient levels of control;

(3) An identification of impacts aggravated by accelerated development;

(4) A comparison of significant differences in impacts among coal-producing regions; and

(5) A description of the uncertainty of synthetic fuels environmental data and environmental effects.

This study emphasizes the processing and end-use phases of coal liquefaction technology to produce transportation fuels during the next several decades.

The approach taken in this study was to collect up-to-date information on the processes and their characteristics important to environmental impacts, and to evaluate important environmental issues and the technical factors affecting them. Members of the research team conducted interviews with environmental engineering and management staff of process development companies and attended several conferences concerned with the development status and the environmental effects of synthetic fuels processes. Staff at the DOE National Laboratories and at EPA laboratories conducting and managing environmental and health research were contacted and information relevant to the current status of environmental research was obtained. The information included in this report is thus based on work conducted by developers, government agencies, and profit and nonprofit research organizations.

The information has been organized to characterize the existing policy framework, to assess the status of environmental control technologies, and to describe levels of air emissions, water effluents, and other residuals characteristic of the technologies. These environmental data were related, using selected examples, to existing conditions in several regions in the nation in order to assess the level of impact; examples were chosen primarily from the Northern Great Plains, Eastern, and Interior coal regions. Conclusions were then drawn about what were the major factors affecting potential impacts, the potential conflicts with existing legislation, and the major environmental uncertainties.

The remainder of this chapter discusses very briefly projections for transportation fuel demands and coal resources. Chapter II presents an overview of the major processes for converting coal into liquid fuels, emphasizing the important similarities and differences among processes potentially commercial within the next 20 years. Chapter III analyzes the environmental problems and possible mitigating measures in three categories: air quality, water quality, and solid wastes. Ecological effects and human health and safety issues are discussed in chapters IV and V, respectively.

B. TRENDS IN TRANSPORTATION FUEL DEMANDS

To provide a perspective of the magnitude of the problem facing production of transportation fuels, it is appropriate to review present and forecasted needs. In 1980 the transportation energy sector consumed approximately 9.6 MMb/d of petroleum. Table I.1 shows that in 1980 motor fuel accounted for 6.7 MMb/d, jet fuel 1.1 MMb/d, and diesels 1.4 MMb/d. There is a wide range of estimates on future transportation fuel demands, depending on assumptions

TABLE I.1 CURRENT AND FORECASTED TRANSPORTATION FUEL DEMANDS (MMb/d)

	1980	1990	2000
Motor fuel (gasoline)	6.7	5.6-6.1	4.2
Jet fuel	1.1	1.3-1.4	1.7
Diesel fuel	1.4	2.0-2.1	2.7
Other	.5	.4	.3
Total transportation	9.7	9.3-10.0	8.9

Sources: NPC 1980; Phillips Petroleum Company 1980.

about oil prices, efficiency improvements, GNP growth, etc. For example, a recent study by the National Research Council had scenarios with ranges from 5 to 12.9 MMb/d for transportation energy demand in the year 2010, with their "moderate" scenario showing a demand of roughly 9.9 MMb/d (NRC, CONAES 1980, p. 88). Table I.1 also shows projections for the years 1990 and 2000 from recent industry studies (NPC 1980; Phillips Petroleum Company 1980). These projections show total needs about the same by the year 2000, but a decrease of 37 percent for gasoline and increases of 54 and 92 percent for jet and diesel fuels, respectively. In short, it is generally expected that with anticipated improvements in engine efficiencies, total transportation fuel needs by the year 2000 may not change and are likely to drop somewhat, even with increased population growth and economic activity.

A complicating factor that must be considered in assessing any future sources for transportation is the mix between gasoline, diesel fuel, and jet fuel, as is reflected in Table I.1. This is important because the characteristics of gasoline needed for conventional automobile engines differ greatly from that needed by diesel and jet engines. For example, jet and diesel engines cannot tolerate significant concentrations of aromatic hydrocarbons (e.g., benzene and toluene) which are premium components providing high octane to motor fuels.[1] The different synthetic fuel technologies produce fuels with greatly different characteristics. An important question is which synthetic fuel technologies should be selected to provide the appropriate mix of transportation fuels.

C. COAL RESOURCES

There are 283 billion tons of recoverable reserves of coal in the U.S., distributed as shown in Figure I.1. Bituminous coals are found in the Eastern, the Interior, and the Southern Rocky Mountain coal provinces. Subbituminous coals are found primarily in the West. Lignites are found primarily in the Northern Great Plains, and the Gulf Coast.

Differences in coal deposits can be important to coal liquefaction technologies. Important differences with environmental and economic significance include:

---

[1] One important characteristic of gasoline which has a great effect on engine performance is the "octane number." The light aromatics (benzene, toluene, and xylene) all have high octane numbers and give good performance in gasoline engines. The requirements for diesel engines, on the other hand, are quite different. Diesel fuels are rated on "cetane number." Aromatic hydrocarbons have low cetane numbers and yield poor performing diesel fuels. For jet engine fuels, an important criterion is the smoke they produce. Aromatic hydrocarbons, in today's engines, are notoriously bad performers giving off lots of smoke. While engines might be developed to overcome this problem, they are not yet available nor are they likely to be in the near future.

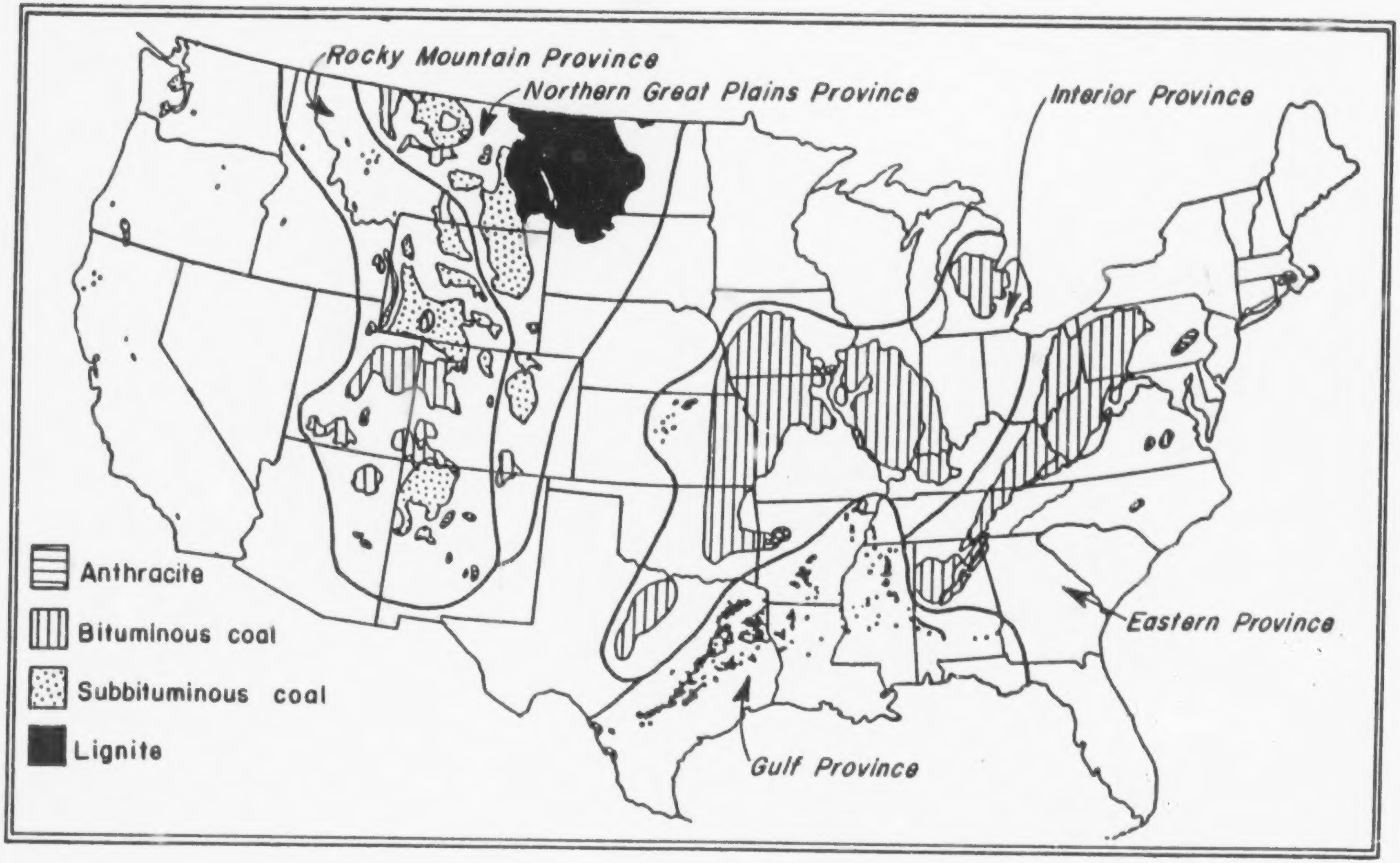
Rocky Mountain Province
Northern Great Plains Province
Interior Province
Eastern Province
Gulf Province
Anthracite
Bituminous coal
Subbituminous coal
Lignite

Figure I.1: Distribution of Coal Resources in the Coterminous 48 States

Source: University of Oklahoma, S&PP 1975.

(1) Seam thickness, size, and depth of deposits: Coal liquefaction technologies require large quantities of coal; e.g., a 50,000 b/d plant will require roughly 220 million tons of coal over a 30 year lifetime. Generally, thick beds found in large deposits close to the surface provide the most economic sources of coal and result in the least land disturbance per unit of energy produced (see Chapter IV). It is expected that coal liquefaction plants will be constructed near to their sources of coal to reduce transportation costs;

(2) Ash content and composition: The ash content of coal contributes substantially to solid waste disposal problems. Also, lower ash coal provides for handling less ash through conversion process stages, which is a particular problem for direct processes. Heavy metals and other chemicals affect the potential toxicity of ash;

(3) Oxygen content: The oxygen content of coal can vary significantly; generally, lower quality subbituminous coals and lignite have much more oxygen. For some conversion technologies (the "indirect processes" described in Chapter II) the oxygen must be removed by the use of costly hydrogen;

(4) Sulfur content: With higher sulfur coals, then, generally the costs of environmental controls increase. On the other hand, some technologies depend on the pyrite (an iron sulfide) content to chemically assist the liquefaction process; and

(5) Btu content: Larger quantities of low-Btu lignites must be mined and transported for each barrel of coal liquids produced. On the other hand, mining and transportation impacts are lowest for the high-Btu bituminous coals.

Table I.2 summarizes differences in coal composition among the major coal producing areas of the coterminous 48 states. The Eastern region has low to moderate ash coals with a range of moderate to high sulfur levels. The Interior Province generally has the highest sulfur content. Gulf Coast lignites and western coals are relatively low in sulfur and some of the coals have a relatively high ash content, although this varies substantially among basins within the region. Due to the low-Btu content, lignites in the

TABLE I.2: SUMMARY OF MOISTURE, ASH, SULFUR AND HEAT CONTENT OF COAL FROM SOME MAJOR COAL-PRODUCING SEAMS IN THE UNITED STATES

Region/State	Moisture (%) Range	Moisture (%) Average[a] (approx.)	Ash (%) Range	Ash (%) Average[a] (approx.)	Sulfur (%) Range	Sulfur (%) Average[a] (approx.)	Heat (Btu/lb) Range	Heat (Btu/lb) Average[a] (approx.)
Eastern								
West Virginia		2.9	4-20	7	0.6-14	2.2	1,400-14,800	13,800
Pennsylvania	1.1-3.9	2.5	4.2-10.8	7.5	0.7-3.3	2.0	13,040-14,340	13,690
Eastern Kentucky	-	3.2	-	3.9	-	0.9	-	14,200
Tennessee	2.0-7.6	4.8	1.9-10.5	6.2	0.7-3.2	2.0	12,630-14,290	13,460
Virginia	1.8-2.2	2.0	4.7-5.8	5.3	0.5-0.7	0.6	14,600-14,870	14,735
Alabama	1.2-4.0	2.6	4.9-19.8	12.4	0.5-2.6	1.6	11,570-14,700	13,135
Interior								
Illinois	4-18	11.0	8-12	10.0	2-5	3.5	10,100-12,700	11,400
Indiana	-	-	5-30	12.0	0.7-7.3	3.3	9,100-14,000	12,800
Western Kentucky	-	5.0	-	10.5	-	3.15	-	12,940
Gulf Coast								
East Texas	8-34	20.0	5-38	15.0	.5-3.5	1.0	6,500-8,000	7,000
West								
Montana	-	-	4.0-5.3	4.6	0.29-0.5	0.37	7,925-9,652	8,633
Wyoming	21.1-36.9	29.7	3.1-12.2	6.0	0.14-1.2	0.48	7,128-9,600	8,203
North Dakota	33.5-43.8	37.9	4.4-8.0	6.2	0.2-1.4	0.6	5,960-7,487	6,783
Arizona	7.0-17.4	10.35	3.4-6.7	5.2	0.4-0.9	0.6	10,450-12,060	11,617
New Mexico	-	13.2	-	20.4	-	0.72	-	9,200

Source: Modified from U.S., DOE 1979 p. E-24. Texas Lignite data adapted from Radian Corp. 1979, and Kaiser n.d.

[a] Most values are averages, some are midranges.

Gulf Coast and Northern Great Plains are expected to be converted at "mine-mouth" plants.

Coal liquefaction processes vary in their suitability to the various coal types. Eastern and Interior bituminous coals are generally more suitable for direct liquefaction processes than western subbituminous coals and lignite (see Chapter II). This difference in suitability is generally due to the higher liquids yield from bituminous coals (Epperly, Plumlee and Wade 1980; and Fluor 1979). The yield differences for direct liquefaction processes are due to the additional hydrogenation requirements needed for coals with high oxygen content, characteristic of western coals and lignite (Simbeck, Dickenson and Moll 1980). This hydrogenation requirement is represented by the hydrogen distance in Figure I-2. The higher capital and operational cost for hydrogenation generally overpowers the lower cost advantage of lower rank western coals and lignites (Simbeck, Dickenson and Moll 1980; Fluor, 1979).[1] Currently, direct process plants have been proposed only for eastern locations.

The indirect processes can utilize a wide range of coals. Although, like direct processes, they have higher yields per ton of coal for higher rank coals, they do not directly hydrogenate coal and, thus, do not operate at such an economic disadvantage with the lower cost subbituminous coals and lignites. For these reasons

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[1] The SRC II process also is not suitable for western coals because of their low pyritic iron content. This iron acts as an essential catalyst for the liquefaction reactions in the SRC II process (See Chapter II).

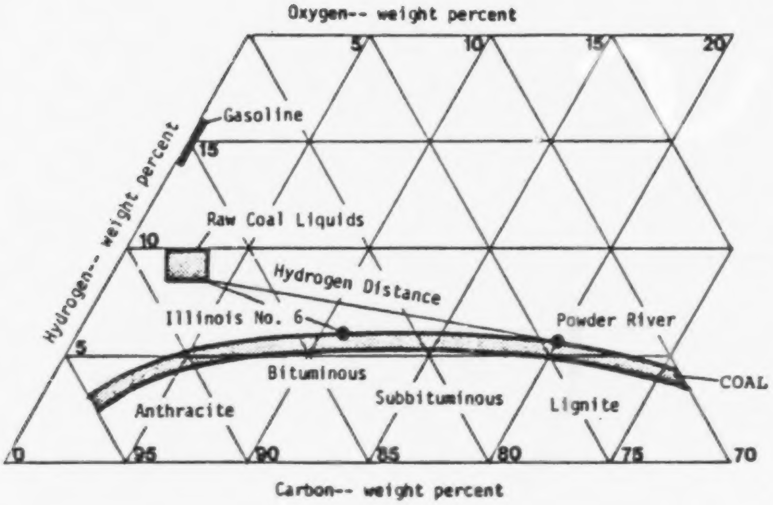

Figure I.2: Direct Coal Liquefaction Favors Bituminous Coals Due to Hydrogen Requirements for Oxygen Removal

Source: Adapted from Simbeck, Dickenson and Moll 1980.

indirect process plants have been proposed for western as well as Interior and Eastern province locations. In addition some studies indicate that indirect processes may be more favorable in western locations due to the lower coal costs (Simbeck, Dickenson and Moll 1980).

The caking or agglomerating properties of coal at high temperature restrict some gasifier and reactor applications. However, recently even Lurgi gasifiers which were susceptible to clogging have been designed to accept caking coals.

In summary, direct processes are more likely to be deployed in Interior and Eastern coal regions than in Rocky Mountain, Northern Great Plains, or Gulf Coast coal provinces. Indirect processes have greater flexibility for utilizing a wide range of coals, potentially can be located in a wide range of U.S. locations, and are perhaps favored in the West if coal costs remain lower there.

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CHAPTER II

OVERVIEW OF TECHNOLOGIES

A. INTRODUCTION

The technology for producing synthetic fuels from coal was first developed in Germany during the 1920's and 1930's. Between 1936 and 1939, nine plants using the Fischer-Tropsch process were constructed in Germany with an output of approximately 14,000 b/d (Anastai 1980, p. 4).

There are two basic methods of getting liquid fuels from coal--the direct and the indirect routes--both based on chemistry developed in Germany before World War II. The direct way, the hydrogenation route, involves fracturing the complex coal molecules and adding hydrogen to the fragments; the smaller the fragments and the more hydrogen added, the lighter the liquids produced.[1] On the other hand, the indirect technique first converts (by incomplete combustion) the coal to a medium-Btu gas (primarily carbon monoxide and hydrogen). After purification the carbon monoxide and hydrogen produced are then combined catalytically to give the liquid fuel--either methyl alcohol or hydrocarbons, depending upon the catalyst. Because of the long development time required only those processes which are already in advanced pilot plant or commercial stage can be considered to contribute significant quantities of transportation fuels by 2000.

---

[1] More intensive development of direct liquefacton processes started in the sixties.

B. DIRECT COAL CONVERSION

Today there are three processes under study in at least an advanced pilot plant stage:

- Solvent Refined Coal II (SRC II);[1]
- H-Coal; and
- Exxon Donor Solvent (EDS).

They differ mainly in their mechanical features (e.g., reactor design) and in whether or not the hydrogenation is done catalytically.

The highly simplified flow scheme in Figure II.1 illustrates how similar the three direct processes are. Each requires:

(1) A coal preparation step--drying and grinding;
(2) Preparation of a coal slurry--ground coal plus solvent;
(3) Preheating the coal slurry near reactor temperature;
(4) A liquefaction step in the reactor (roughly 850°F, 1,500 to 2,500 pounds per square inch [psi]);
(5) The separation of hydrogen from the reactor effluent in order to recycle hydrogen; and
(6) Distillation of the liquid from Step 5 to provide products, recycle solvent, and an ash-laden liquid slurry.

They differ principally in that SRC II uses no catalyst, H-Coal has catalyst in the liquefaction reactor, and EDS partially

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[1] The SRC I process also is a direct process producing liquid products. Because it has been developed to produce a clean solid fuel and because it is closely related to the SRC II process, it is not emphasized in this report.

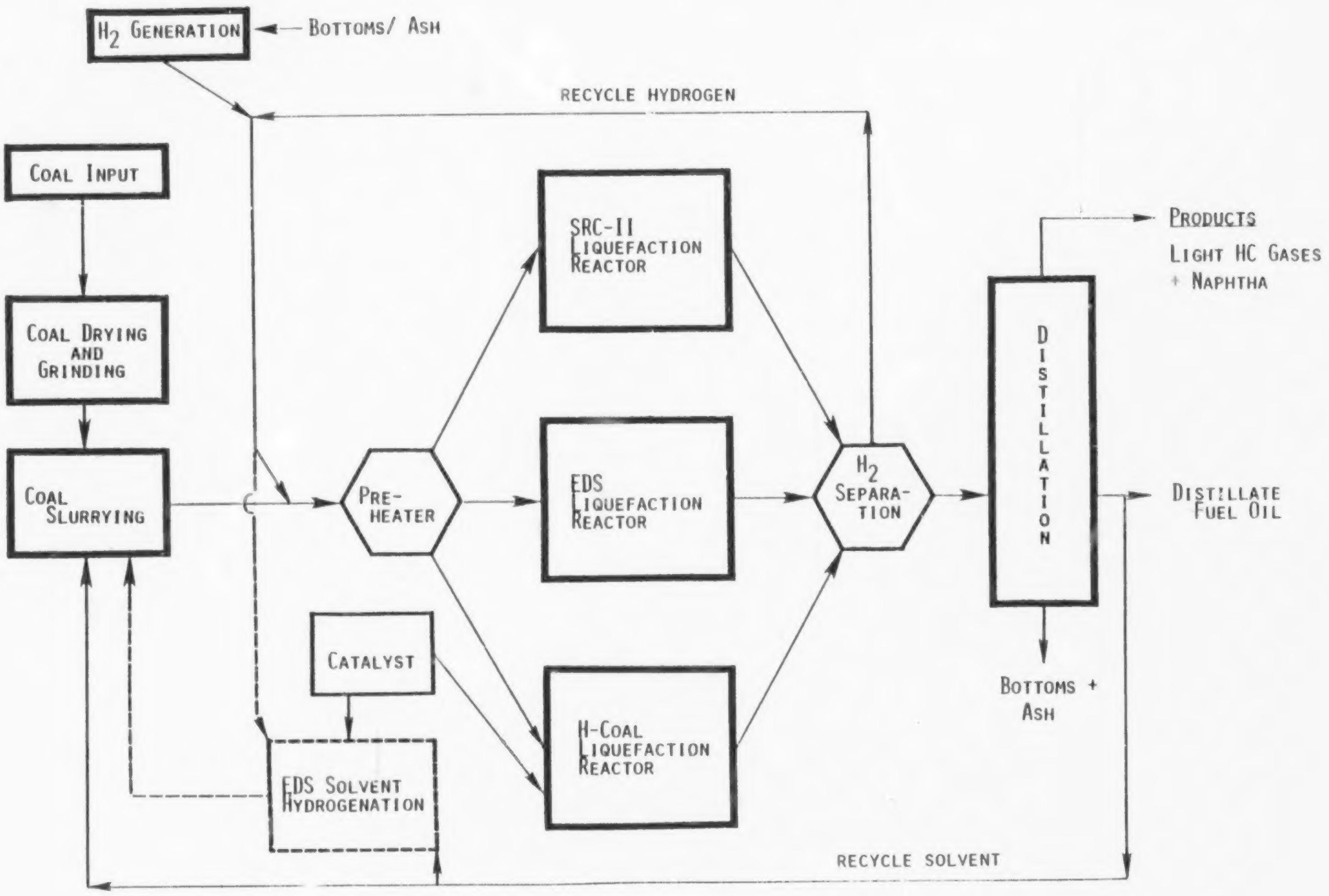
H2 GENERATION
BOTTOMS/ ASH
RECYCLE HYDROGEN
COAL INPUT
COAL DRYING AND GRINDING
COAL SLURRYING
PRE-HEATER
CATALYST
EDS SOLVENT HYDROGENATION
SRC-II LIQUEFACTION REACTOR
EDS LIQUEFACTION REACTOR
H-COAL LIQUEFACTION REACTOR
H2 SEPARATION
DISTILLATION
PRODUCTS
LIGHT HC GASES + NAPHTHA
DISTILLATE FUEL OIL
BOTTOMS + ASH
RECYCLE SOLVENT

Figure II.1: Simplified Flow Scheme for Direct Coal Liquefaction Processes

hydrogenates, catalytically, the recycle solvent in a separate step. Following the separation of the lighter liquids and distillate the disposition of the heavy "bottoms" (which also contain most of the ash) is a common problem. It can be used as a fuel or, via partial combustion, as a hydrogen source; the choice depends upon the energy balance and economics of specific commercial plant designs.

These processes typically produce 2.4 to 2.8 barrels of liquid per ton of coal.[1] These liquids include light products such as naphtha which can be converted to high octane motor fuel and heavier liquids which can be upgraded to higher grade fuels (but this requires a large consumption of hydrogen).[2] Some nitrogen, sulfur, and trace elements remain in the fuels and can be further removed by refining to meet existing fuel grades.

C. INDIRECT PROCESSES

There are three basic indirect processes for producing transportation fuels from coal:

(1) Methanol (methyl alcohol);

(2) Mobil's Methanol-to-Gasoline conversion (MMG):[3]

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[1] Based on 12 million Btu's per pound of coal. Lower ranked coals may yield somewhat less liquid.

[2] See Section II.D for a more detailed discussion of products produced. As indicated there, the product slate of these technologies can be varied.

[3] Mobil's process involves fixed bed catalytic conversion of methanol. Since scale-up of fixed bed processing has low technological risk and methanol synthesis is commercial, Mobil's process status is essentially commercial.

(3) Fischer-Tropsch.

All indirect processes first gasify coal to produce a synthetic gas--a mixture of carbon monoxide and hydrogen (plus impurities). There are three commercial coal gasifiers in operation--Lurgi, Koppers-Totzek, and Winkler. Two advanced pilot plant gasification processes under development are the Texaco Partial Oxidation process and Shell-Koppers--a pressurized version of the Koppers-Totzek process. As shown in Figure II.2, any of these three gasifiers will produce gas which, after purification, can feed the catalytic converters. One type of catalyst will produce methanol and is used commercially today on carbon monoxide/hydrogen mixtures obtained from natural gas (methane); maximum plant production levels are 7,000 to 10,000 b/d. Methanol can be blended with gasoline or, with appropriate engine modifications, can be used directly as motor fuel. A new catalyst, developed by Mobil, can convert methanol directly into gasoline without heavy liquid by-products. The Fischer-Tropsch process is in commercial operation by SASOL[1] in South Africa using Lurgi gasifiers. All of these indirect routes yield clean fuels since sulfur, nitrogen, and ash are removed in the gasification step.

D. PRODUCTS FROM COAL LIQUEFACTION PROCESSES

Table II.1 summarizes the product slate expected from six kinds of coal liquefaction technologies. The relative proportion of each type of product can be varied; the proportions shown on Table II.1

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[1] South African Coal, Oil, and Gas Corporation, Ltd.

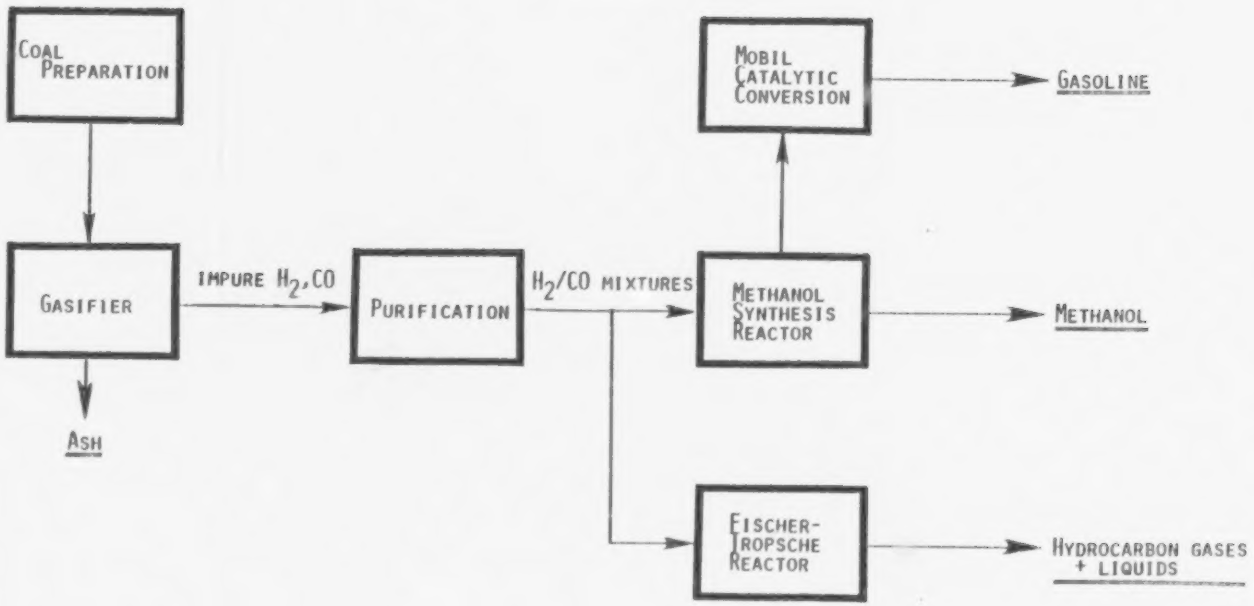
COAL PREPARATION
GASIFIER
ASH
IMPURE H_2,CO
PURIFICATION
H_2/CO MIXTURES
METHANOL SYNTHESIS REACTOR
MOBIL CATALYTIC CONVERSION
GASOLINE
METHANOL
FISCHER-TROPSCHE REACTOR
HYDROCARBON GASES + LIQUIDS

Figure II.2: Simplified Flow Scheme for Indirect Liquefaction Processes

TABLE II.1: COAL LIQUEFACTION PRODUCTS SUMMARY (plant feed rate = 25,000 tons/day dry coal)[a]

Process	Product[b]	Amount/Day		Thermal Equivalent[c] (10^6 Btu/day)	Product Share (%)
Indirect					
Fischer-Tropsch	Gasoline	18,200	bbl	91,000	.35
	LPG	18,800	bbl	75,200	.30
	No. 2 Oil	1,200	bbl	6,240	.02
	Fuel Oil	2,000	bbl	12,600	.05
	Med. Btu Gas	90.7	MMscf	36,280	.14
	C2-Gas	37.2	MMscf	37,200	.14
MMG	Premium Gasoline	52,700	bbl	263,500	.90
	LPG	7,300	bbl	29,200	.10
Methanol	Methyl Fuel	113,400	bbl	294,840	.93
	Methanol	8,400	bbl	22,680	.07
Direct					
EDS	Propane	3,270	bbl	10,464	.03
	Butane	3,500	bbl	12,250	.04
	Naphtha	19,900	bbl	103,480	.30
	Fuel Oil	28,700	bbl	180,810	.52
	C2-Gas	41.9	MMscf	41,900	.12
H-Coal					
Syncrude	Naphtha	31,900	bbl	165,880	.44
	Fuel Oil	24,300	bbl	153,090	.41
	Gas	56.3	MMscf	56,300	.15
SRC II	LPG	5,500	bbl	22,000	.06
	Naphtha	10,700	bbl	55,640	.14
	Fuel Oil	45,300	bbl	285,390	.74
	Gas	23.1	MMscf	23,100	.06

Source: Rogers and Hill 1979.

[a] Source data has been adjusted so that all electric power is assumed to be generated on site with an efficiency of 10,000 Btu/kWh. Original product slates have been adjusted to a common basis of source coal with a heating value of 11,200 Btu/lb-dry.

[b] Fuel oil means low sulfur boiler fuel comparable to No. 6 oil. Gases shown as MMscf = million standard cubic feet.

[c] See Appendix B for thermal equivalent values used in conversion of barrels to Btu's.

are from Rogers and Hill, 1979, which reflected plans for demonstration and commercial plants based on published sources and discussion with developers (Rogers and Hill 1979).

Fuel oil generally refers to industrial fuel, also commonly called No. 6, Bunker C, or residual fuel. There are variations in the properties for the oils in this category. This fuel is commonly used for boilers in industry or for utility power generation. No. 2 oil listed in the table has a viscosity similar to diesel fuel but would require upgrading to meet diesel fuel standards.

Naphtha is a large fraction of the direct process liquids and is a generic term for a distillate product which is not commonly sold on the open market. It is an intermediate refinery stream which ends up as gasoline, diesel fuel, and specialty products.

Liquid petroleum gas (LPG) is a commercial product consisting mostly of propane and butane. It can be used as a fuel in appropriately modified vehicles.

The use of Fischer-Tropsch technology appears to be favored for producing naphthas suitable for diesel fuel production, whereas the MMG process appears to be the favored technology for production of high octane unleaded gasoline. Methanol should not be overlooked as it can be used for production of higher value products including methyl tertiary butyl ether (MTBE) and tertiary amyl methyl ether (TAME)(Simbeck, Dickenson and Moll 1980), which are used as fuel additives. Current testing also indicates methanol could be used in spark-ignition internal combustion engines and combustion turbines (Simbeck, Dickenson and Moll 1980). Methanol is sold commercially but not now on a scale required for the transportation fuels market. Although it can be used in gasoline engines as an acceptable replacement, its solvent properties may cause damage to engine gaskets. Methyl fuel is essentially methanol with some retained process water. A mixture of methanol with 5 to 20 percent diesel may find use in diesel type engines (Simbeck, Dickenson and Moll 1980). However, careful analysis is required to assess the potential of substituting methanol mixtures for gasoline and diesel fuel.

Oil refineries may favor direct coal liquids because they have the existing facilities for up-grading coal-derived naphtha and have existing markets for coal-derived fuel oil to replace conventional residual oil (see following section on refining and upgrading). The displaced residual oil might then be upgraded to higher value liquids with some modifications to existing refineries (Simbeck, Dickenson and Moll 1980). The location of current residual markets and capital cost of direct coal liquefaction might favor construction of direct coal liquefaction plants in the eastern U.S. near high rank bituminous coals (Simbeck, Dickenson and Moll 1980).

From a products viewpoint, indirect coal liquefaction might be favored by energy "entrepreneurs," chemical companies, and oil refiners not having strong residual markets. As indicated above, indirect coal liquefaction produces the highest value liquid fuels, e.g., methanol, MTBE, gasoline, and diesel fuel. Texas and Louisiana lignites have potential as feedstock for indirect coal liquefaction plants on the Gulf Coast where there is a high demand for chemical feedstocks. The lack of residual fuel markets may also favor indirect liquefaction of low cost western subbituminous coal. However, because of the high value of the products, indirect coal liquefaction can also be considered for midwest and eastern coals (Simbeck, Dickenson and Moll 1980).

The gasoline shown in Table II.1 is low in octane from a simple Fischer-Tropsch process. It is lower quality than the regular grade sold in the U.S. market. The premium gasoline is 93 Research Octane Number and is the same as sold in the U.S.; it is directly produced from the MMG process.

On a thermal basis, more fuels are produced by the direct liquefaction processes than the indirect processes. As indicated in Table II-2, Fischer-Tropsch liquefaction (with a Lurgi gasifier) is the least efficient process.

However, if the value of the fuels for transportation purposes are compared, the indirect process compares favorably, except for Fischer-Tropsch. Two bases for transportation fuel efficiency are included in Table II-2, "Transportation Efficiency" and "Light Liquids Efficiency." "Transportation Efficiency" is a measure of the Btu value of the product mix relative to a high grade transportation fuel--unleaded premium gasoline.[1] The transportation efficiency index is based on the Btu output of each product, weighted against a value scale based on the economic cost of transforming

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[1] It should be noted that direct coal liquefaction products require much upgrading for use as diesel or jet fuels. The aromatic hydrocarbon content makes diesel or jet fuel applications costly and, therefore, unlikely.

TABLE II.2: COMPARISON OF PRODUCT EFFICIENCY OF LIQUEFACTION PROCESSES (percent)

Process	Thermal Efficiency[a]	Transportation Efficiency[b]	Light Liquids Efficiency[c]
Indirect Processes			
Fischer-Tropsch	46.2	41.5	30.8
MMG	52.3	51.6	52.3
Methanol	56.7	54.6	56.7
Direct Processes			
EDS	62.3	45.1	22.5
H-Coal	67.0	49.7	29.6
SRC II	69.0	44.2	13.9

[a] The total hydrocarbon energy divided by the total plant input with steam and electricity produced on site.

[b] As above, but the total energy output is adjusted by a factor to reflect the cost of upgrading the heavier fuel fractions to gasoline grade transportation fuel (see Appendix B).

[c] As (a) above, but only fuels which can be used directly for transportation are included: propane, butane, LPG, methanol, methyl fuels, naphtha, No. 2 oil, and gasoline.

that product to a high grade fuel. For example, unleaded premium gasoline is weighted 1.0, and the more efficient fuels of butane and propane are weighted 1.08 and 1.07 respectively. Fuel oil is penalized, with a weighting of 0.56. The weighting factors and calculation are explained in more detail in Appendix B. Although the weights are based on economic costs and prices, they provide an approximation of transportation energy value of the product mixes. The weights provide an approximation of the inefficiencies in upgrading coal-derived naphthas and fuel oils to transportation products. As compared to thermal efficiency, the transportation efficiencies are lower across the board, reflecting the relative energy cost to up-grade to transportation fuels. Methanol and MMG processes have the highest "Transportation Efficiency," and Fischer-Tropsch and SRC II, the worst. However, Fischer-Tropsch suffers at a disadvantage in the comparison, because its naphthas and No. 2 fuel oil fractions are more suitable as fuels than similar fractions from direct processes. Thus, Fischer-Tropsch may not be distinguishable from other processes in about the 45 percent transportation efficiency range.

"Light liquids" efficiency in Table II-2 is an index that only measures the thermal efficiency for producing fuels that can be directly used for transportation purposes with no or little upgrading. In addition to gasoline and methanol, this includes the propane, butane, LPG, naphtha and No. 2 fuel oil fractions. In this case Methanol and MMG have the highest efficiency, and the EDS and SRC II processes compare less favorably.[1] On this basis, these latter processes would require two to four times the plant capacity to produce an equivalent amount of fuel that could be easily used by the transportation sector.

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[1] As indicated earlier, all the direct processes can be adjusted to shift amounts of heavy and light fractions produced at some economic cost. For example, the H-coal feed rate can be slowed and more hydrogen can be added to "lighten" the product mix. As another example, in the EDS process, recycle of the heavy bottoms ("bottom recycle") can decrease the fuel oil fraction from 52 percent down to about 33 percent, with about a 20 percent increase in proportion of naphtha and lighter fuels in the product stream. (Epperly, Plumlee and Wade, 1980).

E. UPGRADING AND REFINING

Comparison among the coal liquefaction processes should take into account the demand for the various products and the feasibility and efficiency of refining and upgrading to meet market needs. From an environmental perspective, important factors include:

- How efficient will be the refining process to produce transportation fuels;
- Will grass roots refining capacity be needed; and
- What types of refinery impacts may occur.

The two classes (direct and indirect) of coal liquefaction processes have different refining needs. As indicated above, the MMG process produces a product directly usable as transportation fuel. The Methanol process can be considered to manufacture a blending stock for transportation fuels used in conventional engines, a feedstock for the MMG process, or pure ethanol to be used directly in appropriately modified engines. For these technologies, the conversion efficiencies described in the previous section represent the efficiencies for final products. For the Fischer-Tropsch process, a low octane gasoline (unsuitable for motor fuel unless upgraded) is a major product along with other transportation fuels such as diesel fuel. As indicated previously, some fuel oils produced by the Fischer-Tropsch process would require cracking and reforming to make transportation fuels.

As described earlier, the direct coal liquefaction processes produce light, middle, and heavy distillate fractions, with proportions varying depending on the specific process type and the amount of "recycle" or the residence time liquids spend in reactor vessels. The light distillate or naphtha fractions of direct processes make good gasoline blending stock after reforming. The EDS and H-coal processes can produce up to two-thirds naphtha and one-third fuel oil to maximize liquids with transportation value. The SRC II process, as indicated earlier, produces a greater amount of heavy products, although its product slate is also variable. In all cases, however, significant refining of the range of liquids is required to produce high proportions of transportation fuels. Because of the extensive refining requirements, including large hydrogen requirements, refining to transportation fuels is an energy intensive process. Table II.3 indicates the efficiency of refining SRC II liquids to gasoline and jet fuel. The low efficiency range, from about 75 to 80 percent, reflects the extensive cracking and hydrogenation requirements to upgrade these liquids.

The energy efficiency of refining improves as additional fuel oil remains in the product output (Frumkin and Sullivan 1980). Based on discussions with staff of direct process developers, they expect to utilize naphtha fractions as a gasoline blending stock and use heavier fractions to back out petroleum as a boiler fuel (Gulf Mineral Resources Co. 1980; Exxon Research and Development Corp. 1980; and Hydrocarbon Research Corp. 1980). In addition, Environmental Impact Statement Documentation for SRC II and SRC I facilities indicates that middle and heavy fractions will be used for boiler fuels (U.S., DOE 1981a, 1981b).

For these reasons, over the short term, environmental disturbances from additional refinery requirements for both direct and

TABLE II.3: EFFICIENCY OF REFINING SRC II LIQUIDS[a]

Process Characteristics	Total Input Btu Requirement[b] (10^6 Btu/day)	Product Output[c] (10^6 Btu day)		Efficiency
		Gasoline	Jet Fuel	
High severity hydrotreating	356,483	75,260	204,060	78.4
Intermediate severity hydrotreating	347,697	89,967	188,243	80.0
High severity hydrotreating and fluid catalytic cracking	352,423	265,000	--	75.2
Intermediate severity hydrotreating and single stage hydrocracking	335,524	265,000	--	79.0

[a] Refinery characteristic from Frumkin and Sullivan 1980.

[b] Includes a composite of SRC II syncrude, boiler fuel and electricity. SRC syncrude = 5.76 x 10^6 Btu/bbl; boiler fuel = 6.2 x 10^6 Btu/b; electricity = 10.5 x 10^6 Btu/MW.

[c] Gasoline = 5.3 x 10^6 Btu/b, jet fuel = 5.7 x 10^6 Btu/b.

indirect coal liquids appear to be minimal. However, over the longer term if demand for transportation fuels cannot be met by petroleum liquids, refining direct process liquids to transportation fuels may be more favorable (Chevron Research 1981). Under these circumstances the most efficient refining operations for direct liquids would be from new grass roots refineries (Frumkin and Sullivan 1980), and refining coal liquids may be a significant environmental issue. Many of the issues are closely related to those for the liquefaction process itself, such as concerns about air and water quality, siting, and health considerations. The liquefaction processes generally can be ranked (from major requirement to no requirement) on the basis of additional refining requirements to meet transportation demand as follows: (1) SRC II; (2) H-coal and EDS; (3) Fischer-Tropsch; and (4) Methanol and MMG.

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CHAPTER III

CONTROL TECHNOLOGY AND AIR, WATER QUALITY, AND SOLID WASTE ISSUES

The objective of coal liquefaction technologies is to transform a solid fuel high in polluting compounds and mineral matter into liquid fuels with low levels of sulfur, nitrogen, trace elements, and other pollutants. In these processes, large volumes of gaseous, liquid, and solid process streams must be continuously and reliably handled and separated into useful end products and waste streams. These waste streams must be treated in a way to protect environmental values. This chapter first introduces the general pollution control process requirements for both direct and indirect coal liquefaction technologies. Following this introduction, control technology and environmental issues are discussed for air emissions, water effluents, and solid wastes.

A. ENVIRONMENTAL CONTROLS OVERVIEW

1. Waste Streams and Controls

Figures III.1 and III.2 are simplified diagrams showing effluent streams which must be dealt with in direct and indirect processes, respectively. While there are significant control process stream differences between the direct and indirect plants, both routes to liquid fuels must deal with the sulfur, nitrogen, and

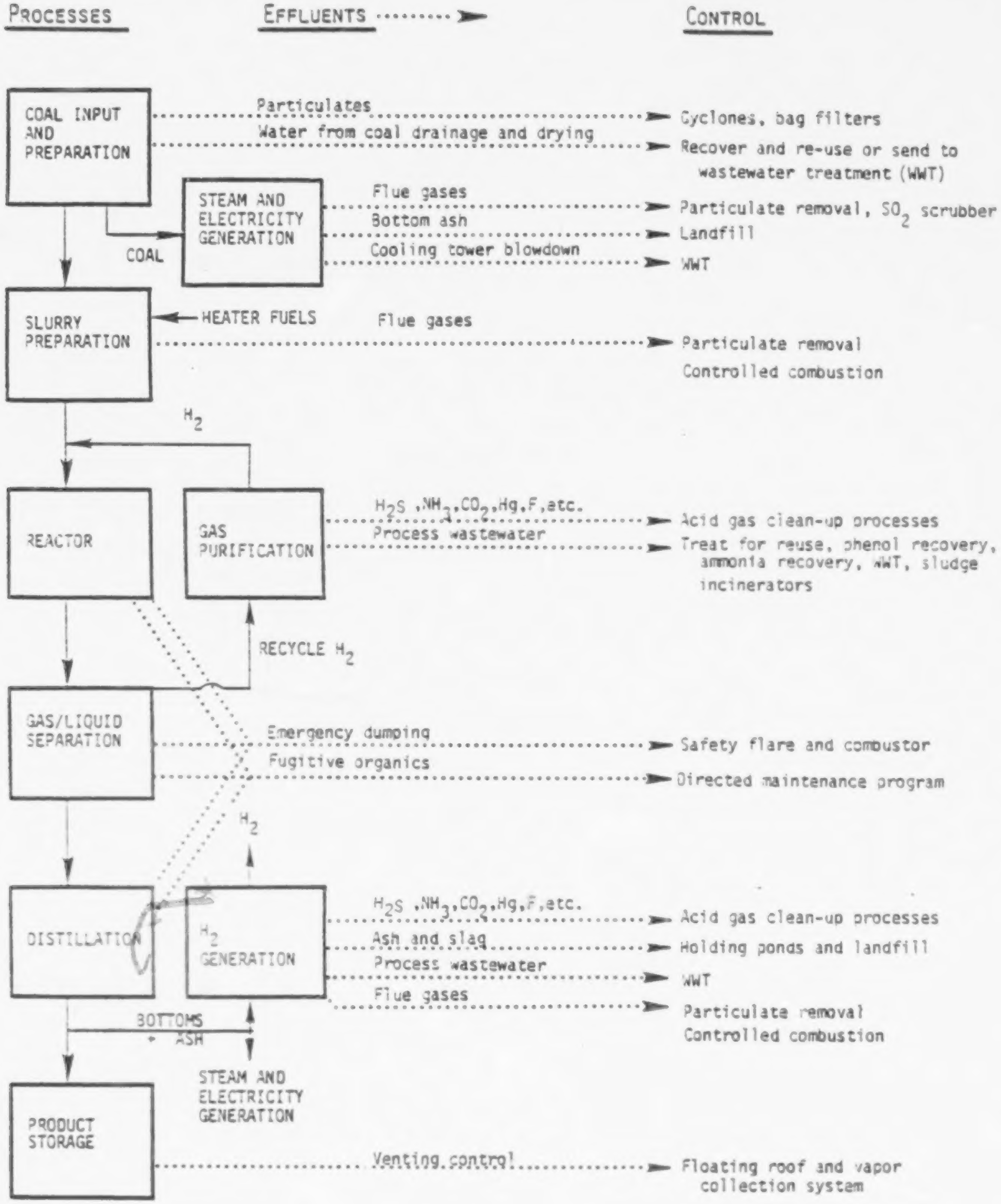
PROCESSES
EFFLUENTS
CONTROL
COAL INPUT AND PREPARATION
Particulates
Cyclones, bag filters
Water from coal drainage and drying
Recover and re-use or send to wastewater treatment (WWT)
STEAM AND ELECTRICITY GENERATION
COAL
Flue gases
Particulate removal, SO_2 scrubber
Bottom ash
Landfill
Cooling tower blowdown
WWT
SLURRY PREPARATION
HEATER FUELS
Flue gases
Particulate removal
Controlled combustion
H_2
REACTOR
GAS PURIFICATION
H_2S, NH_3, CO_2, Hg, F, etc.
Acid gas clean-up processes
Process wastewater
Treat for reuse, phenol recovery, ammonia recovery, WWT, sludge incinerators
RECYCLE H_2
GAS/LIQUID SEPARATION
Emergency dumping
Safety flare and combustor
Fugitive organics
Directed maintenance program
H_2
DISTILLATION
H_2 GENERATION
H_2S, NH_3, CO_2, Hg, F, etc.
Acid gas clean-up processes
Ash and slag
Holding ponds and landfill
Process wastewater
WWT
Flue gases
Particulate removal
Controlled combustion
BOTTOMS + ASH
STEAM AND ELECTRICITY GENERATION
PRODUCT STORAGE
Venting control
Floating roof and vapor collection system

Figure III.1: Simplified Direct Liquefaction Process-Waste Stream Sources and Control.

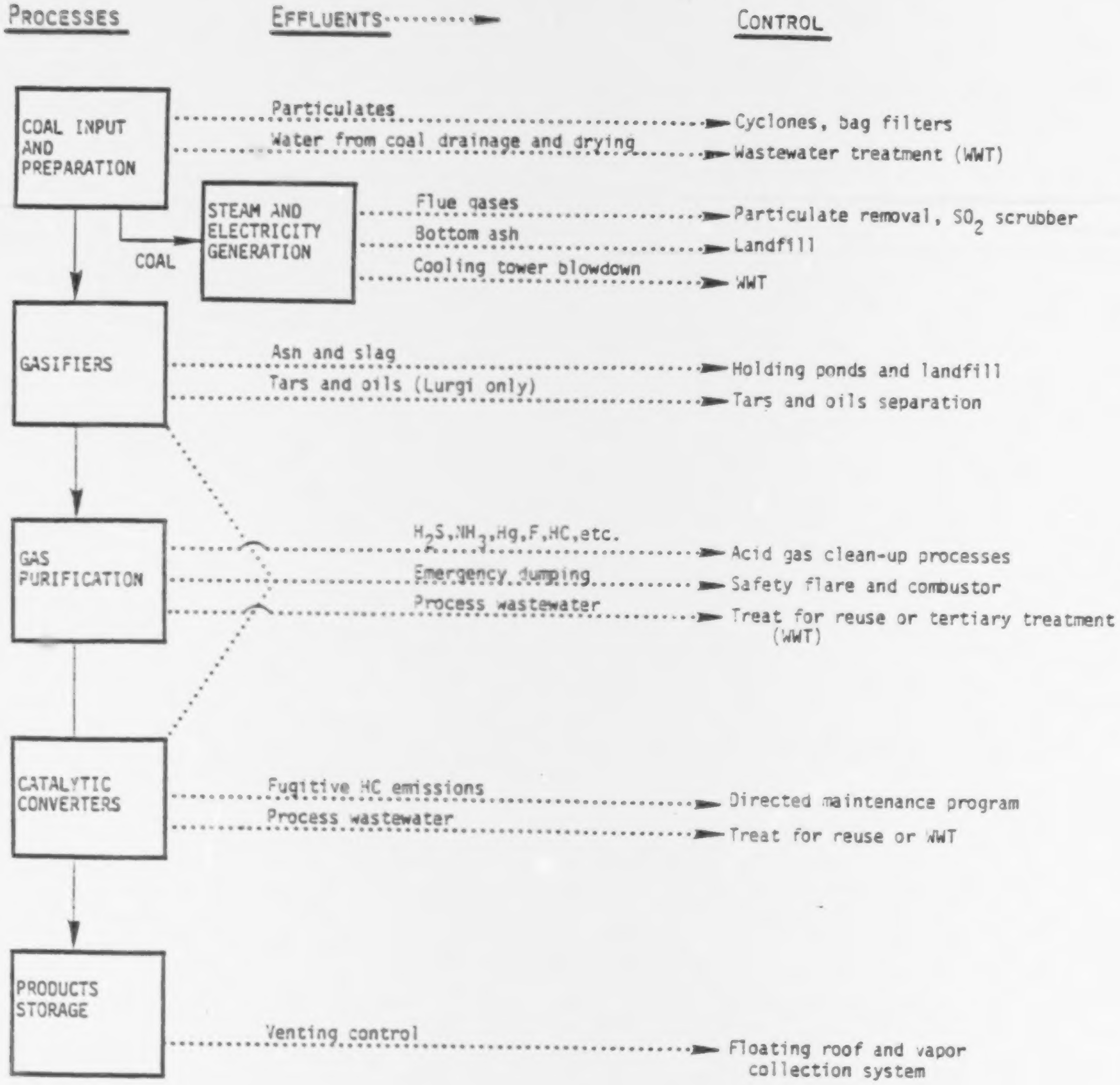
PROCESSES
EFFLUENTS
CONTROL
COAL INPUT AND PREPARATION
Particulates
Cyclones, bag filters
Water from coal drainage and drying
Wastewater treatment (WWT)
STEAM AND ELECTRICITY GENERATION
COAL
Flue gases
Particulate removal, SO2 scrubber
Bottom ash
Landfill
Cooling tower blowdown
WWT
GASIFIERS
Ash and slag
Holding ponds and landfill
Tars and oils (Lurgi only)
Tars and oils separation
GAS PURIFICATION
H2S,NH3,Hg,F,HC,etc.
Acid gas clean-up processes
Emergency dumping
Safety flare and combustor
Process wastewater
Treat for reuse or tertiary treatment (WWT)
CATALYTIC CONVERTERS
Fugitive HC emissions
Directed maintenance program
Process wastewater
Treat for reuse or WWT
PRODUCTS STORAGE
Venting control
Floating roof and vapor collection system

Figure III.2: Simplified Indirect Liquefaction Process-Waste Stream Sources and Control

mineral matter in the coal feed. Potentially toxic hydrocarbons and deleterious oxygenated chemicals generated during processing which enter the gas or liquid effluent streams must also be controlled. The following discussion briefly summarizes and compares the sources of pollutants, which are described in more detail in sections III-B through III-D.

The generalized direct process diagrammed in Figure III-1 has all those waste streams found in indirect processes, plus additional waste streams associated with preheaters, the removal of undesirable liquids and gases from the liquefaction reactor, and catalyst disposal. Sources of major pollutants from direct and indirect coal liquefaction include:

(a) Coal feed preparation. Unloading, storing, pulverizing, drying, and transporting coal results in sources of particulates, trace elements, and hydrocarbons. These materials can enter the environment mechanically (from dust), through runoff, and vaporization. Both direct and indirect processes require similar coal preparation steps.

(b) Coal slurry preparation. All direct processes require slurry preparation (indirect processes generally do not). Heating the slurry to temperatures above 800°F and at pressures above 2,000 psi requires a preheater furnace, fired by coal, liquids, or fuel gas. The preheater furnace is large, is an important source of the process heat input, and is a major source of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), nonmethane hydrocarbons (NMHC), particulates (TSP), carbon monoxide (CO), and waste heat (vented to the atmosphere).

(c) Direct process reactor, including gas/liquid separation. All direct process reactions hydrogenate and fragment coal molecules which produce a wide range of reduced nitrogen, sulfur, and ammonia compounds, and entrained particulates (ash) with heavy metals that must be removed. This removal separates the gases hydrogen sulfide (H_2S), ammonia (NH_3), hydrogen (H_2) and the "sour water" (which also contains H_2S, NH_3, carbon dioxide (CO_2), phenolics and polynuclear aromatic hydrocarbons). For H-Coal and EDS processes, catalyst replenishment or disposal is required.

(d) Gasifier. The partial combustion of coal produces a range of reduced sulfur and nitrogen compounds in addition to the desired hydrogen, CO, and methane. Indirect processes have large gasifier sections, whereas direct processes have much smaller units for the production of hydrogen. Gasifiers generally produce large amounts of NH_3, H_2S, and particulates, which must be separated. Lurgi gasifiers also produce tars, oils and phenol.

(e) Fugitive hydrocarbon emissions. Both direct and indirect processes have fugitive hydrocarbon emissions from leaking valves and fittings and storage units. However, direct processes (which are more complex than indirect processes) have more sites for fugitive emissions compared to indirect processes. Fugitive emissions are typically the largest source of hydrocarbon emissions in a liquefaction plant.

(f) Other catalytic sections. Both direct and indirect processes employ large fluid or fixed bed catalysts in various stages of the plant. Indirect Fischer-Tropsch and Methanol processes require periodic catalyst reprocessing or disposal. The hydrogen plant in direct processes employs a range of catalysts. All processes have catalysts in sulfur plants and tail gas clean-up plants associated with environmental control sections that require reprocessing or disposal.

(g) Auxiliary boilers and furnaces. A major source of ash waste, thermal discharge, and SO_2, NO_x, and TSP are auxiliary boilers and furnaces. Large coal-fired boilers can be the major sources of SO_x, NO_x, and particulates. Fuel gases and liquids combusted in various heater and steam reformer furnaces are major sources of air emissions in direct processes.

As indicated above, the major sources of pollutants are quite different for the generic liquefaction types. For air pollutants, direct processes typically have relatively large criteria pollutant emissions streams from heaters, principally liquid slurry, recycle solvent, and hydrogen preheaters; hydrogen plant steam reformer furnaces; and distillation heating sections. However, the largest nonmethane hydrocarbon emissions originate from fugitive emissions, as the entire process is contained in pressure vessels. Indirect processes have a large gasifier emission source which is also the major source of process heat. Direct processes also have gasifiers, but these sections are relatively smaller. Both direct and indirect processes require steam and electricity generated through on-site boilers that are significant sources of SO_x, NO_x, and particulates, depending on the type of fuel used.

The direct and indirect process solid waste streams vary depending on how the direct process "bottoms" are treated. Generally these heavy bottoms with their entrained ash will be fed to a gasifier for hydrogen generation. In this case the largest solid waste streams from both direct and indirect processes will be similar in character: an ash with very low organic content. Scrubber sludges (and ash) will also originate from the on-site boilers fed high-sulfur coal. All direct and indirect processes will have various catalysts that will be reprocessed or disposed of. The replacement of catalysts in H-coal and EDS processes involve larger volumes of catalysts than other processes.

All processes generate sludges in the wastewater treatment process due to the need to remove dissolved and suspended chemicals from wastewaters. Direct processes and Lurgi indirect processes have more sludge to dispose of than other indirect processes.

The environmental control technologies which are planned for synthetic fuel plants to handle these waste streams are largely based on present engineering practice. The processes have been selected from those used by petroleum refining, petrochemical, coal-tar processing, and power generation industries. Importantly, the current designs for coal liquefaction plants are not final. For example, to date only in the H-Coal pilot plant have the wastewater effluents been sent through a complete environmental control system. Some of the larger operating pilot plants (e.g., 250 tons per day [tpd] EDS) do not have pollution control systems of their own and waste streams are fed into control systems of adjacent refineries. For that reason, there will be some uncertainty of the performance of proposed control systems until commercial module or pioneer plants are operated. Based on past experience in successfully extrapolating bench scale tests to commercial operations, it is expected that performance on liquefaction plant streams will not deviate significantly from expectations for conventional[1] pollutants under "normal" operations.[2]

However, there are several factors in coal liquefaction that differ from previous refinery and petrochemical experience. These include: (1) the trace elements in the coal mineral matter; (2) the processing and movement of large quantities of solids; and (3) presence of polynuclear aromatic hydrocarbons (in direct process and Lurgi).[3] While the fate of trace elements has been projected for gasification,[1] the fate of trace elements in direct liquefaction processes has not been established. Although most of those trace elements are expected to remain with the ash, plans have been made for careful material balances in the large pilot plants in order to determine whether or not hazardous levels of any of those elements are in the effluent streams. If hazardous levels are found, new techniques to separate and dispose of them may need to be developed.

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[1] Conventional pollutants include biological system demanding substances, suspended solids, fecal coliform, changes in pH, oil, and grease.

[2] Normal operations refer to performance when all process streams perform according to design specifications. It does not include start-up, shut down, upset, or emergency conditions.

[3] Some of the polynuclear aromatic hydrocarbons have been determined to be carcinogenic; see Section III.F for further discussion of the carcinogenicity issue.

Because coal contains large quantities of ash, typically between 4 and 20 percent (U.S., Congress, OTA 1979, p. 57), handling large quantities of solids in many of the process streams will be necessary. This problem of handling liquid streams containing large amounts of entrained solids under these temperature and pressure conditions is largely outside industrial experience. Importantly, solids handling is a difficult mechanical problem; for example, the movement of solids is more susceptible to occurrences of flow blockage and pipe erosion. New design and testing of mechanical systems must accompany each phase of plant scale-up or modification which affects the process stream containing solids. The indirect processes minimize this solids handling problem because ash is removed from the gasifier in the first step of the liquefaction process.

The presence of large complex aromatic compounds in direct coal liquefaction and Lurgi gasification process streams and end-products

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[1] For example, in the case of the WESCO gasification project; see U.S., DOI, BuRec 1976.

products presents relatively new problems, although the coal tar industry has experience with these compounds, but under very different circumstances. Generally, a goal in coal liquefaction is to minimize the amount of these complex aromatic compounds in the product to enhance combustion and safety characteristics. Economic methods to minimize polynuclear aromatic compounds in high volume process streams from direct liquefaction represents a new application of hydrogenation technology currently used in the petroleum industry. Hydrogenation and hydrocracking in coal liquefaction are important aspects of existing research to make products both safer to handle and more clean burning.

2. Standards for the Design of Controls

Coal liquefaction plants will be regulated under a large number of state and federal environmental laws. For air, water, and solid wastes the most important of these laws are the Clean Air Act, the Federal Water Pollution Control Act, and the Resource Conservation and Recovery Act of 1976. Regulations promulgated under these laws have resulted in requirements to apply environmental control technologies (e.g., "best available controls") for most large industrial processes. However, because of their state of development, design standards or "Best Available Control Technology" (BACT) definitions have not yet been developed for coal liquefaction. As discussed in subsequent sections of this chapter, plants must meet applicable ambient environmental standards. Plants are currently being designed with environmental controls that developers believe are adequate to obtain permits for air and water discharges and solid waste disposal.[1]

As industry is designing the present generation of coal liquefaction demonstration plants, EPA is drafting Pollution Control Guidance Documents (PCGD's) which provide general multimedia pollutant control guidance for the liquefaction technology prior to commercialization.[2] The specific objectives of the PCGD's are to:

- Inform the Environmental Impact Statement (EIS) review process;
- Provide guidance for permit writers;
- Provide guidance for control standards; and
- Convince developers to install "best available controls."

The guidance documents are to be made available for indirect liquefaction technologies in 1981 and for direct liquefaction technologies in 1982 (U.S., EPA 1980). The PCGD's are not legally binding for industry but are advisory for permitting and EIS review officials (U.S., EPA 1980).

Industry is now designing liquefaction plants with effluent and emissions levels which are intended to achieve their assumed "most probable limits" (i.e., limits near where they expect EPA to set the standards) (Exxon 1980). These effluent and discharge levels are based on their experience with standards established for petroleum, by-product coke, and electric utility industries. For example, one developer indicates that wastewater treating schemes will utilize "Best Available Technology" (Green 1980, p. 4). The air emissions for boilers will utilize scrubber systems designed as BACT for utility boilers (Green 1980, p. 5). Air emission controls for the liquefaction section will be adopted from the petroleum refining industry.

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[1] As discussed in subsequent sections, potential conflicts with environmental standards can be anticipated, however.

[2] Environmental Guidance Documents were specified in a memorandum of understanding between the Department of Energy (DOE) and EPA on coordinating procedures for establishing Environmental Protection Standards for emerging nonnuclear energy technologies. See Appendix B in U.S., DOE 1979.

3. Conclusions

This overview of planned environmental controls highlights the following points:

(1) Industry development of design standards and technology is based on petroleum and utility industry experience.

(2) Environmental controls for coal liquefaction differ in four basic ways from experience in the petroleum industry:

- The fate of trace elements must be identified, and then controlled;
- Solids handling presents mechanical design and operational uncertainties;
- Large quantities of complex aromatic hydrocarbons (especially for direct processes) must be segregated, transformed, or utilized on site; and
- The reactor temperatures associated with indirect liquefaction processes are higher than normally found in the petroleum industry.

(3) Government pollution control standards under developemnt are not based on actual commercial-scale experience with these technologies.

For some critical health-related effluents and emissions, BACT provides an inadequate approach towards environmental control. This is because many of the noncriteria pollutants are the ones most significant in health effects (see Chapter V). There are no ambient standards for these pollutants; and, there are also no agreed-upon control technologies for coal liquefaction. For these reaons, BACT is a weak basis for developing environmental controls.

The control approaches, emission levels, and environmental impacts discussed in the following sections provide indications of environmental problems and issues for specific media. However, five kinds of uncertainty underly these impacts:

(1) Uncertainty in design of both demonstration and commercial plants;

(2) Uncertainty in standards for control technologies;

(3) Uncertainty in technological performance (such as emission controls);

(4) Uncertainty in levels of commercial development which might occur; and

(5) Uncertainty in environmental transport and effect on receptor populations.

B. AIR QUALITY ISSUES

1. Legislative Overview

The Clean Air Act provides for the maintenance or improvement of air quality. Sections of the law that will significantly affect a synthetic fuel industry are:

(1) National Ambient Air Quality Standards (NAAQS) for criteria pollutants;

(2) Prevention of Significant Deterioration (PSD) regulation;

(3) New Source Performance Standards (NSPS); and

(4) National Emission Standards for Hazardous Air Pollutants (NESHAP).

The NAAQS listed in Table III.1 are of two types: primary standards protecting human health and secondary standards protecting public welfare, including plants and animals, visibility, and buildings.[1] To maintain air quality in areas that are currently cleaner than the limits specified by NAAQS, these "attainment" regions were divided into three classes: (1) "pristine" areas such as national parks and wilderness areas, (2) areas where moderate pollution and industrial growth are allowed, which includes most of the U.S., and (3) areas where major industrial development is foreseen.[2] For these classes, increments of pollution above existing baseline levels are allowed. These PSD increments now exist only for TSP and SO^2, as specified in Table III.1. For areas above the NAAQS (i.e., "nonattainment" regions), an "offset policy" applies: briefly, reductions in existing sources must be found to more than offset the increases from any new facility. In addition, stringent controls are required, termed the "lowest achievable emissions rate," to minimize any potential increases and to achieve a proportional reduction in emissions to allow for the possibility of industrial growth.

At the present time any large (greater than 250×10^6 Btu/hr) boilers in a synfuels facility would be treated separately from the

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[1] States are also required to set ambient air quality standards --and they may be more stringent than the federal ones. In the western U.S., for example, several states have set standards for some pollutants which are more strict than the federal standards.

[2] No PSD Class III have been established.

TABLE III.1: FEDERAL AMBIENT AIR QUALITY STANDARDS AND PREVENTION OF SIGNIFICANT DETERIORATION STANDARDS (concentrations in micrograms per cubic meter)

Pollutant	Ambient Air Quality Standards		Prevention of Significant Deterioration Standards[a]		
	Primary (human health)	Secondary (public welfare)	Class I	II	III
SO_2					
Annual arithmetic mean	80		2	20	40
24-hour maximum	365		5	91	182
3-hour maximum		1,300	25	512	700
TSP					
Annual geometric mean	75	60	5	19	37
24-hour maximum	260	150	10	37	75
NO_x(as NO_2)					
Annual arithmetic mean	100	100			
Oxidants (as O_3)					
1-hour	240	240			
CO					
8-hour maximum	10,000	10,000			
1-hour maximum	40,000	40,000			
Lead					
Quarterly	1.5	1.5			
Nonmethane hydrocarbons					
3-hour maximum (6-9 am)	160[b]	160[b]			

NO_2 = nitrogen dioxide O_3 = ozone

Source: Adapted from U.S., Congress, OTA 1980, pp. 266-267.

[a] Allowable incremental change in ambient concentration.

[b] Not a standard, a guide to show achievement of O_3 standard.

rest of the synfuel facility and are subject to NSPS.[1] A NSPS is defined to require the application of the best system of continuous emission reduction, taking into account the cost, the health and environmental impacts from nonair sources (e.g., solid waste disposal), and energy requirements. However, NSPS for coal synthetic fuels facilities are only in the early planning stages, and standards have not been developed (Farmer 1979).

At the present, NESHAP have been established for beryllium, asbestos, mercury, vinyl chloride, benzene, and radionuclides. Of these, only the standards for mercury and radionuclides, which are trace elements in coal, and benzene could potentially affect synthetic fuel plants. However, under the hazardous air pollution regulations, standards are to be established for regulating airborne carcinogens. The EPA has not established policies and procedures for dealing with airborne carcinogens, but such a policy is under review (Farmer 1979; Inside EPA 1980a, p. 13).

Finally, air emission levels will be affected by the PCGD's which are being prepared by EPA (see Section III.A). These documents will be considered by regulators in evaluating permits.

2. Air Emission Levels and Controls

As indicated previously in figures III.1 and III.2, air emissions can be expected from:

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[1] Under the "bubble concept" each emission source, such as coal-fired boilers, would not be treated separately, but rather emission standards would be set for the total facility. At the present time, it is uncertain how the "bubble concept" might be applied to synthetic fuel facilities.

Source:	Pollutants:
• Coal preparation	Coal dust (particulates)
• Slurry heaters	Particulates, SO_2, NO_x, trace elements, etc.
• Gasification or hydrogen production	H_2S, NH_3, CO, CO_2, NO_x, particulates, SO_2, trace elements, etc.
• Steam or electricity generation	Particulates, SO_2, NO_x, trace elements, etc.
• The liquefaction step and other liquid handling systems	Fugitive non-methane hydrocarbon (NMHC) emissions
• The vent and flare system	SO_2, NMHC, NO_x, CO
• Sludge incinerators	Particulates, CO, SO_2

Removal of particulates will use conventional methods such as cyclones, water scrubbers, electrostatic precipitators, and, for ultimate clean-up, bag filters. Suitable combinations of those techniques can be used to keep particulate emissions at design standards during normal operation.[1]

Sulfur emissions arise from two sources; under reducing conditions (e.g., gasification and liquefaction), H_2S is produced; under oxidizing conditions (e.g., steam production), SO_2 is generated. H_2S is handled by absorption into a solvent. recovery of H_2S from the solvent (regeneration) and chemical conversion of the H_2S to elemental sulfur. There are a number of commercial processes which can be selected to economically remove 99.9 percent of the sulfur from the gas stream (Fluor 1979). The remaining 0.1 percent of the sulfur is released to the atmosphere in the form of SO_2 (rather than H_2S). The SO_2 produced by burning coal in a large steam boiler must, according to NSPS, be controlled by "continuous reduction in emissions,"[1] For steam boilers producing on-site power or process heat these large boilers (greater than 250 million Btu/hr) must achieve SO_2 emission levels less than 1.2 pounds per million Btu output. For smaller boilers state standards apply (these are generally similar to the federal NSPS of 1.2 pounds SO_2 per million Btu).

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[1] The narrative following discusses design standards and possible emission levels during "abnormal" operating conditions. At present NSPS for particulates have been established only for coal-fired boilers and coal preparation facilities.

Ammonia (NH_3) will be absorbed from the gas stream and recovered since it is a valuable by-product. Unrecovered NH_3 will be converted to NO_x and emitted.

Available estimates on emissions from point sources in five types of coal liquefaction plants are summarized in Table III.2. These estimates were derived from the existing literature (see Appendix Table A.1 for details). All estimates were normalized to a commercial-size facility producing 50,000 b/d of liquids. However, the kinds of liquids produced are not equivalent in quality; that is, they will not provide for the same amount of transportation (see Chapter II, Section D).

The range of emissions rates given in Table III.2 can be caused by a variety of factors, including (adapted from U.S., DOE 1980a, Appendix B):

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[1] Continuous controls apply to normal operations, in contrast to intermittent controls which might, for example, be applied only during adverse meteorological conditions. "Continuous controls" does not mean the controls are always operating, for example, during start-ups, shut-downs, and upset conditions.

TABLE III.2: AIR EMISSIONS ESTIMATES FOR COAL LIQUEFACTION PROCESSES[a]
DURING "NORMAL" OPERATING CONDITIONS
(tpd from a 50,000 b/d facility)

Process	Particulates	SO_2	NO_x	CO	HC	CO_2
Indirect						
MMG	0.5-7.5	6.0-14.0	5.0-15.5	NC	NC	21,000
Fischer-Tropsch	1.0-6.0	9.0-14.0	5.0-23.6	NC	NC	21,000
Direct						
EDS	0.3-0.75	16.0-27.3	5.0-12.6	1.0-5.5	0.01-1.0	14,000
H-Coal	0.1-3.5	5.5-10.5	NC	NC	NC	11,200
SRC II	2.0-6.8	5.0-13.6	5.65-10.0	1.5-2.5	2.0-2.2	6,200-14,000

HC = hydrocarbon NC = not considered

[a] Based on data from numerous sources (see Table A.1); includes only emissions of criteria pollutants and CO_2.

(1) Support processes, especially steam and electric power generators, can burn either a "cleaned" process by-product fuel or the feedstock coal itself. The former is less polluting;

(2) Electric power can be purchased from a remotely located power plant, in which case emissions from the power plant are not included with those of the liquefaction facility, or it can be generated on-site, in which case its emissions are included; and

(3) The make up of the coal (e.g., Btu, ash, and sulfur content) affects emissions levels (see Chapter I, Section C).

Variations in these can change emission rates substantially. Another difficulty in comparing emission rates is that the data in the literature are not well documented. For example, specific environmental controls and coal characteristics are not always identical. Given these factors, it is not appropriate to make strict comparisons among the various processes based on the emissions data in Table III.2. In fact, given the uncertainties and the overlap in the available estimates for the alternative processes, there do not appear to be significant differences between the levels of criteria air pollutants emitted by the various processes under normal operating conditions. This result is not really surprising, since, in all the processes the majority of emissions are produced in the auxiliary parts of the liquefaction system; that is, they arise from the coal handling operations, the furnaces, the acid gas treatment system, and the sulfur recovery process. These emission sources are all handled by similar control techniques. Thus, judged on the basis of emission levels of criteria air pollutants under "routine operating conditions," it is not possible to distinguish among the technologies at this time.

For perspective on the relative magnitude of these emissions, a coal-fired power plant meeting NSPS (0.6,[1] 0.7 pounds per million Btu's of coal burned for particulates, SO_2, and NO_x, respectively) would emit about 6, 120, and 140 tpd when using the same amount of coal as a 50,000 b/d coal liquefaction facility.[2] Comparing these figures with those in Table III.2, we see that synfuel plants emit considerably less SO_2 and NO_x than a power plant consuming the same amount of coal. For particulates, emissions are nearly equal to the highest emission estimates from liquefaction facilities.

Probably the most serious emissions from an environmental and health viewpoint, and the ones subject to the most uncertainty, may be NMHC[3] from nonpoint sources (i.e., "fugitive" emissions). Fugitive HC emissions arise from equipment leaks including leaks in flanges, valves, and pump seals (Figure III.3). A recent study by Oak Ridge National Laboratory (1980) based on studies by Radian Corporation of fugitive emissions at integrated oil refineries, estimates that total NMHC fugitive emissions from the SRC II demonstration facility during normal operation conditions could be 679

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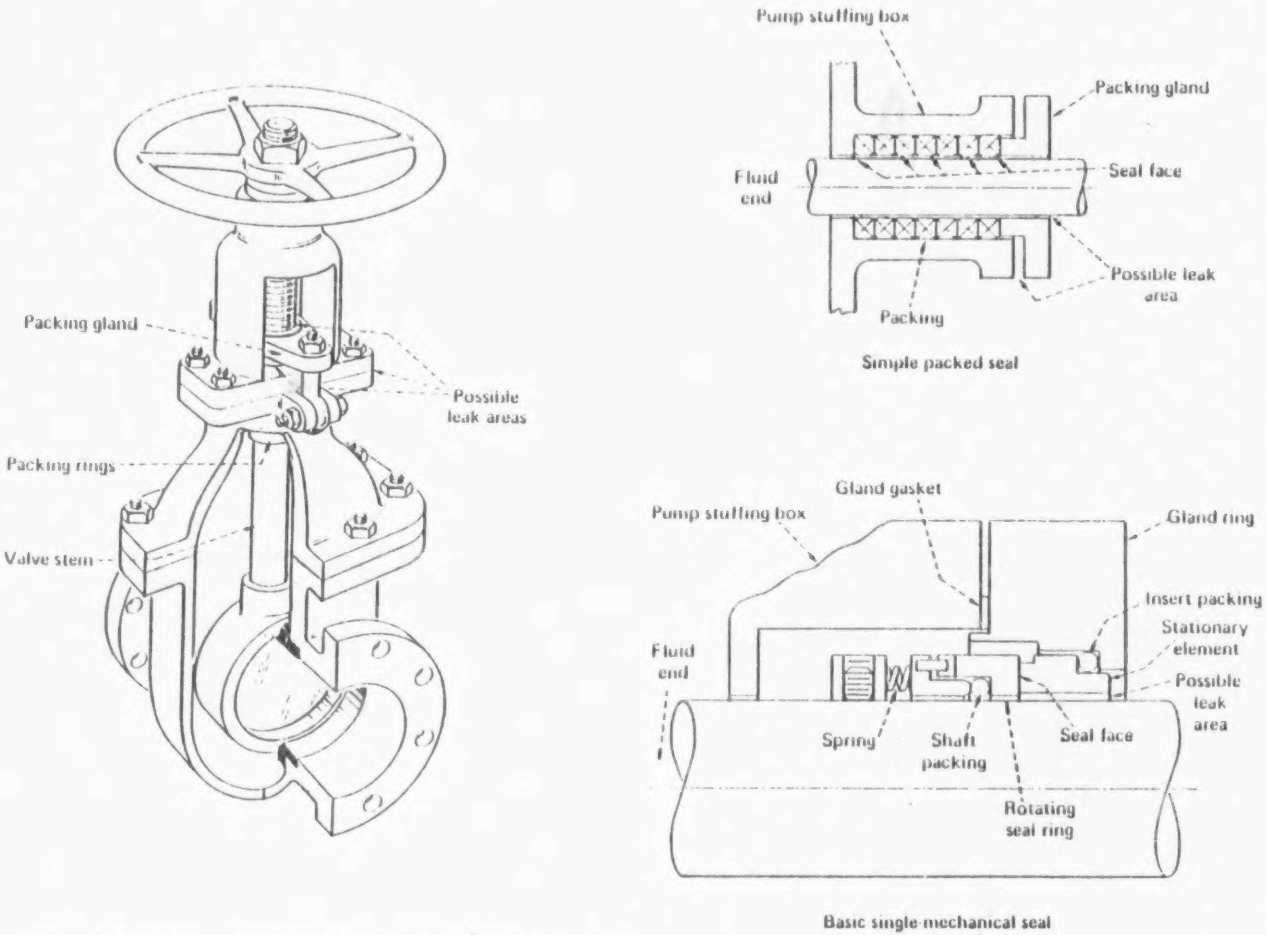
[1] Actually, the SO_2 standard varies with the sulfur content of the coal, but 0.6 pounds of SO_2 per million Btu's can be considered to be a "typical" value.

[2] Based on 0.4 tons of coal per barrel of coal liquid output and 10,000 Btu/lb of coal feed.

[3] Nonmethane hydrocarbons is a very broad spectrum since it includes every hydrocarbon from ethene and ethylene on up to asphalts (i.e., it is everything other than methane itself). Therefore levels of NMHC have no direct relationship to concentrations of carcinogenic hydrocarbons. For example, leaks from propane storage would yield high NMHC values in the complete absence of carcinogenic or mutagenic compounds.


Packing gland
Possible leak areas
Packing rings
Valve stem
Pump stuffing box
Packing gland
Fluid end
Seal face
Possible leak area
Packing
Gland gasket
Pump stuffing box
Gland ring
Insert packing
Stationary element
Fluid end
Possible leak area
Spring
Shaft packing
Seal face
Rotating seal ring

Simple packed seal

Basic single-mechanical seal

Figure III-3: Fugitive Emision Sources from Valve and Pump Seal Leak Areas

Source: Wallace 1979. Used by permission.

tons per year (tpy) in an "unmitigated" case. On the other hand, with a "directed maintenance" program,[1] this could be reduced to 97 tpy. (Note that the emissions data given previously in Table III.2 was based on a "directed maintenance" program, but with emission scaled to a 50,000 b/d facility.) Of the total released, about one pound per hour (about 4 percent of the total release) is thought to possibly cause health problems.[2] This is equivalent to 4 to 5 pounds per hour of potentially health-related NMHC emissions from a commercial facility producing 50,000 b/d.[3]

The extent of fugitive emissions and their composition is a major uncertainty and issue for coal liquefaction. The directed maintenance programs to be used by developers have not been specified (U.S., DOE 1981). It is generally assumed, based on estimates of leak control maintenance practices, that emissions projected from refinery experience can be reduced by a well planned monitoring and maintenance program. For example, the estimates provided for the SRC II and EDS processes generally represent a major emissions reduction compared to a relatively less maintained condition. However, both the original estimates and the reductions represent only informed guesses.

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[1] Directed maintenance is defined to include monitoring of all individual pieces of equipment that could leak to decide when maintenance is required and monitoring during the maintenance to define when the work is sufficient (ORNL 1980).

[2] This is based on studies indicating that the heavy fractions show mutagenic activity and that the light fractions are inactive (see Chapter V); the mid-weight fractions have not been tested and are not included in the one pound per hour (ORNL 1980). The trajectory of toxic and carcinogenic materials in these fugitive emissions is uncertain. Just what fraction of such a stream leaking from a valve would vaporize into the air or drip onto the ground is uncertain. The possibility is that both air and surface water pollution could result.

[3] The SRC II demonstration plant requires about 6,000 tpd of coal; a commercial plant producing 50,000 b/d liquids will require 24,000 to 30,000 tpd of coal.

What constitutes a directed maintenance program has not been rigorously specified. The broad "generic" fugitive emissions controls issued by EPA were developed after considering three approaches to controlling airborne carcinogens (Federal Register 1979):

(1) Require facilities to attain a specified performance level;

(2) Require specific work practices in maintenance; and

(3) Have voluntary guidelines for either performance or work standards.

Voluntary guidelines were judged to be an inadequate response to controlling health risks. Because of the difficulty in specifying levels of performance and assuring compliance, EPA's draft generic standards have focused on a work practices approach that would (a) specify how often inspections for leaks would be made, (b) identify what detection techniques would be used, and (c) require how soon leaks must be repaired. Although final generic standards have not been adopted, the draft regulations are apparently providing some basis for describing the directed maintenance programs now being developed by industry. Important questions concerning a directed maintenance program include:

(1) How often should inspections be performed? Draft SRC II plans would include quarterly inspections for most valves and seals, but EPA has considered inspections intervals that range from yearly to monthly (Federal Register 1979);

(2) What levels of leaking would be permissible? Leak monitoring would take the form of using a probe to inspire air from around a flange, and measuring the concentration of hydrocarbons in the air. Concentrations in the range of 1,000 to 10,000 parts per million by volume (ppmv) are being considered to trigger a corrective activity. The 1,000 ppmv trigger value would account for about 50 to 90 percent of refinery fugitive emission losses (Federal Register 1979);

(3) Would leaks require plant shutdown? While there is some uncertainty, the answer is, "probably not." Repair techniques exist for conducting repairs while streams are flowing, and apparently most repairs would be flange tightening. Stubborn leaks could be welded shut. Closing down a plant or portion of the plant would be avoided as it subjects joints to temperature fluctuations and contributes to more leaks (Exxon 1981); and

(4) Can leaks be controlled by methods other than a maintenance program, such as by enclosing valves or sections of a plant, or by double piping? Double piping has the disadvantages of creating problems from differential expansion of inner and outer pipe walls. Enclosures increase risk in explosions and firefighting (see Chapter V), and would not directly control leaks. Both enclosures and double piping contribute to maintenance problems rather than resolving fugitive emissions (U.S., DOE 1981).

It is apparent that the fugitive emissions problems would be very significant if average refinery practices were common. However, it is also reasonable to expect that a directed maintenance program can significantly reduce hydrocarbon emissions (Wallace 1979). Nevertheless a zero emission and zero risk level of control is not possible. Existing policy calls for construction of demonstration plants and development of hygiene and maintenance programs that essentially test the acceptability of these health and environmental control programs.

From a health effects viewpoint, the most important difference among these coal liquefaction technologies may be that direct process product streams will consist of heavier organic fractions (which are therefore potentially more hazardous) than those produced by the indirect processes. In the indirect processes the coal molecules are "torn apart" and then reformed into light liquids. Thus, potentially toxic organic compounds will not be significant fugitive emissions in the indirect technologies.[1] (For further discussion see Chapter V).

As noted, all of the previous discussion of emission was based on assumptions of "normal operating conditions." However, an important concern is the emissions during "upset" or "emergency" conditions. To illustrate how air emissions can be affected by upset conditions, the following briefly summarizes information on the vent and flare system to be utilized on the SRC II demonstration plant.

When process upsets and emergencies occur, it will require the immediate venting of gases and vapors to relieve internal pressures to prevent safety hazards to personnel and damage to equipment. Because many of the direct process streams will contain known toxic or carcinogenic materials, and therefore small quantities may be contained in the gases and vapors going to the flare, conventional flares (as used in typical chemical and petrochemical processing facilities), are not considered adequate. The currently proposed demonstration plants include a controlled combustion device as part of the flare system, which will provide a higher degree of assurance of complete combustion of materials released under many upset operating conditions. However, emergency situations may require extremely rapid venting of process vessels which will require bypassing the controlled combustor, with the stream(s) directed to an elevated flare (U.S., DOE 1980b p. C-51) (see Figure III.4).

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[1] However, the Lurgi process does produce a liquid stream of heavy oils and tars.

Descriptions of four possible upset conditions for the SRC II demonstration plant and estimates of SO_2 emission levels for each case are given in Table III.3. Scaling these levels to an equivalent 50,000 b/d plant (i.e., multiplying by a factor of 4) and comparing with the emission levels given previously in Table III.2 of 5.0-13.6 tpd, one can see, for example, that a single occurrence of cases B and C would emit approximately as much SO_2 as during 3.8 to 10.3 days and 1.6-4.5 days, respectively, of normal operation. Therefore, it is clear these upset cases could account for significant emission levels, depending on how often they occur. Since there is no experience in operating these technologies, reliable estimates of the frequency of "upsets" are not available (U.S., DOE 1980c). However, such upsets should be expected more often in demonstration plants than in commercial plants.

3. Air Emission Control Costs

Several factors make comparisons of emissions control costs difficult. First, plant designs are only in the initial stages of development.[1] Because emission controls occur throughout a coal liquefaction plant, available data cannot be compared because of different design assumptions as to what constitutes an

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[1] The Pollution Control Guidance Documents (PCGD's) by EPA are to include control costs.

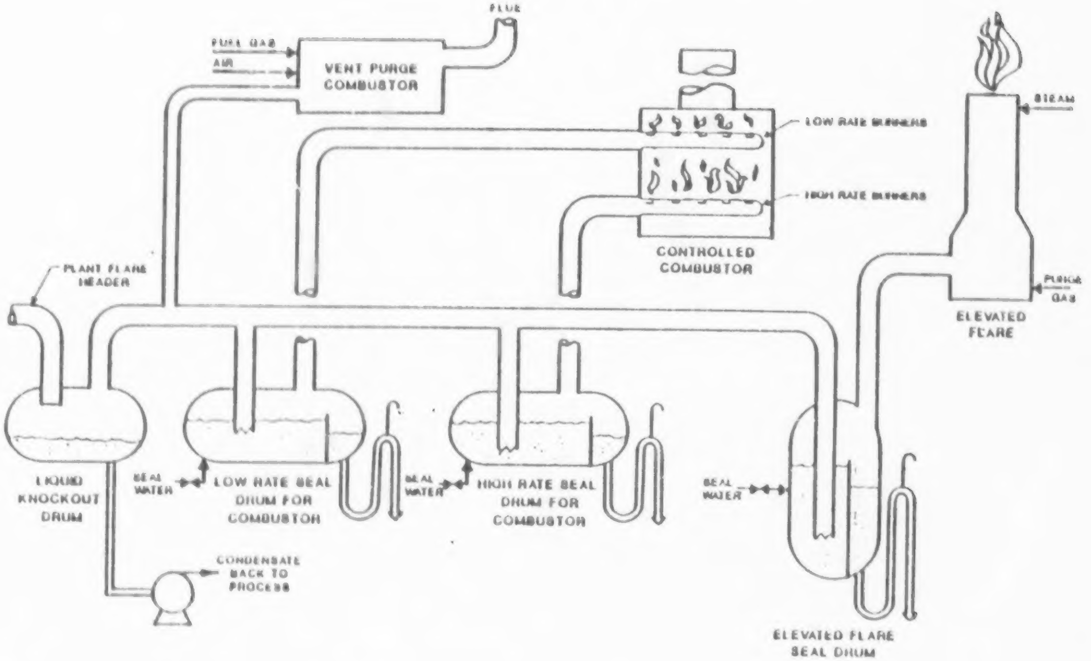
FLUE
FUEL GAS
AIR
VENT PURGE COMBUSTOR
LOW RATE BURNERS
HIGH RATE BURNERS
CONTROLLED COMBUSTOR
STEAM
PURGE GAS
ELEVATED FLARE
PLANT FLARE HEADER
LIQUID KNOCKOUT DRUM
SEAL WATER
LOW RATE SEAL DRUM FOR COMBUSTOR
SEAL WATER
HIGH RATE SEAL DRUM FOR COMBUSTOR
SEAL WATER
CONDENSATE BACK TO PROCESS
ELEVATED FLARE SEAL DRUM

Figure III.4: Elevated Flare and Controlled Combustion System. Gases from Vents and Upsets Enter the Plant Flare Header.

Source: U.S., DOE 1981.

TABLE III.3: ESTIMATED SO_2 EMISSIONS FROM THE FLARE IN THE SRC II DEMONSTRATION PLANT DURING UPSET CONDITIONS

Case	Description	Duration (hours)	SO_2 Emissions (tons)
A	One dissolver blown down from normal operating pressure to near atmospheric pressure in 45 minutes. Blocked in upstream of preheater.	3/4	1
B	Two gasifiers at full load, equivalent to full gas plant capacity. Venting upstream of purification.	2	12.9
C	One dissolver at full rate without purification. Recycle H_2 partially vented to purge CH_4. Gasification providing makeup H_2 to maintain hydrogen partial pressure.	4	5.6
D	Two gasifiers at full rate and pressure. Equivalent to full gas plant rate. Blocked in and blown down in 5 minutes, bypassing purification.	1/12	.03

H_2 = hydrogen

CH_4 = methane

Source: Adapted from U.S., DOE 1980b, p. C-57.

environmental control in contrast to an essential process step. Second, published cost data are limited and those available are based on different tax, depreciation, and interest rates, and these assumptions are not reported in most studies. Third, emission controls for all the process steps are typically not detailed or specified. For example, coal preparation emission control costs are not available in most engineering reports whereas sulfur removal costs typically are specified. As another example, fugitive hydrocarbon emissions are to be reduced by an intensive monitoring and maintenance program (see following discussion), but the costs of such a monitoring and maintenance program have not been specified or separated from other plant maintenance costs in reports now available, primarily as they relate to sulfur emission as described below.

Emission control costs for Lurgi indirect liquefaction will be similar to those for Lurgi synthetic gasification facilities, since the major air emission controls are associated with the gasification sections. Estimates of capital and operating costs for five control approaches for a Lurgi fuel facility are shown in Table III.4. The control options differ primarily on the basis of (1) how auxiliary power and steam are generated, (2) the sulfur control and recovery system used, and (3) the approach for particulate removal.

For options 1, 3, 4, and 5, the costs for emissions control are similar. The higher operating costs for Option 2 is due to the use of air-blown Lurgi gasifiers to produce fuel gas for on-site steam and power generation. In all options most of the air pollution control cost is attributed to the costs associated with pollution control for steam and power generation (use of flue-gas desulfurization (FGD) systems/electrostatic precipators or clean fuel gas). If the total capital and annual operating costs for a 250 MMscf/d commercial Lurgi synthetic natural gas plant are approximately $2 billion and $300 million, respectively, the estimated air pollution control costs shown represent about 2 to 3 percent of the capital costs and 4 to 5 percent of the operating costs (Ghassemi et al. 1979).

TABLE III.4: ESTIMATED COSTS FOR LURGI-AIR EMISSIONS CONTROL OPTIONS
(millions of 1978 dollars)

	Option Number				
Category	1	2	3	4	5
Processes Used:					
Stretford[1]	x	x			x
Electrostatic precipitator	x		x	x	x
Wellman-Lord	x		x	x	x
ADID			x		
Claus			x		x
Beavon			x		x
Incineration	x	x		x	x
Lurgi Fuel Gas		x			
Effectiveness: (emissions in kg/hr)					
SO_2	170	270	300	1,500	520
HC	70	47	40	20	40
CO	240	100	100	50	130
NO_x	1,200	1,500	1,100	1,100	1,200
Particulates	60	Neg.	50	50	50
Costs:					
Total capital	42,000	33,962	53,736	48,465	51,300
Annual Capital[2]	7,709	3,068	9,672	8,723	9,234
Annual Operating	8,198	16,145	6,254	6,175	6,391
Total Annual Cost	15,907	19,213	15,926	14,898	15,625

kg/hr = kilogram(s) per hour

Source: Ghassemi et al. 1979.

[1] Stretford units are used for both Rectisol acid gas treatment and for fuel gas treatment in Option 2. Although the fuel gas Stretford is designed for 100 ppmv H_2S and the Rectisol Stretford for 10 ppmv H_2S, costs on a "per ton sulfur removed" basis are assumed to be the same for both units.

[2] Depreciation and interest = 0.14 x total installed cost. Taxes, insurance, and administration = 0.04 x total installed cost.

The estimated emissions, costs, and energy requirements presented above for Options 1 through 5 have been based on the use of western coal (0.7 percent sulfur, 8400 Btu/lb). Use of coals with higher heat content but the same sulfur percentage should produce acid gases containing somewhat more CO_2 relative to H_2S and carbonyl sulfide. This would not greatly effect the cost of removing H_2S since the major parameters affecting these control processes are the total sulfur or hydrocarbon loadings rather than concentrations or total gas flow rates (Ghassemi 1979). On the other hand, the costs of FGD to remove SO_2 and electrostatic precipitators to remove particulates increase in direct proportion to the gas flow rate so that some savings may be realized with particulate and SO_2 removal in plants using higher heat content coals for steam and power generation.

When higher sulfur coals are used as feed to Lurgi gasifiers, sulfur compounds are expected to increase in acid gases in approximate proportion to feed coal sulfur content. This will tend to increase cleanup costs approximately in proportion to the sulfur content of coal. An increase in sulfur content of the coal fed to utility boilers will also generally result in an approximately proportional increase in flue gas sulfur emissions after treatment by SO_2 removal systems (Ghassemi, et al. 1979).

The only available cost data for air emissions controls for the SRC II commercial plant planned for West Virginia are for the sulfur recovery plant. The capital cost for the sulfur recovery plant is 74 million dollars, or about 5 percent of the total of 1,395 million dollars. Costs for emissions controls of the utility system, coal and slag handling systems, and refining and purification plants are not separated out.

Emissions control costs for the H-Coal plant are also highly dependent on sulfur removal costs. Capital costs for sulfur emissions control for a demonstration H-Coal plant are about 30 percent higher (at $20.5 million) using Illinois coal than for Wyodak coal ($14.1 million) (Fluor 1979).

For the EDS process, capital cost breakdowns of pollution control units are shown in Table III.5. EDS pollution control steps, like pollution control technology in other coal liquefaction processes, are extensions of existing coal and petroleum refining technology. Initial commercial design studies have indicated that about 3.7 percent of the commercial plant costs would be for air pollution control (Epperly 1981).

In summary, emission control costs are influenced by many design and location variables. Important factors include:

- The extent to which electricity and process steam are generated on site. Major (if not most) emission control costs are for cogeneration boilers. If electricity is purchased off-site, these environmental control costs vanish from the accounting books;

- High sulfur coals have significantly higher emission control costs than low sulfur coal;

- Cost estimates on emission controls are limited. This may be due in part, to a widespread need for emissions control devices throughout a liquefaction plant. Emission controls contrast to effluent controls which typically involve a central treatment section so cost data can be more easily compared;

- Emission control cost estimates range between 2 and 5 percent of plant capital costs or higher. However, data are not

TABLE III.5: EDS COST ESTIMATES FOR POLLUTION CONTROL EQUIPMENT[a] (millions of 1978 dollars)

Category	Cost[b]	
Air		
Sulfur Plant	12.8	
Tail Gas Cleanup Unit	3.1	
H_2S Removal Unit	32.7	
DEA Scrubbing	2.8	
DEA Regeneration	5.2	
Subtotal for Air pollution Control		56.6
Water		
Sour Water Treating and Ammonia Recovery	7.9	
Phenol Extraction	10.2	
Wastewater		
- treating	24.3	
- reuse	0.9	
- effluent pipeline	14.9	
Subtotal for Water Pollution Control		58.2
Waste Solids Handling		
Boiler solids	17.0	
Flexicoking solids	20.4	
Disposal landfill	5.2	
Subtotal for Waste Solids Handling		42.6
Cooling Water Facilities		10.3
Total Direct Pollution Abatement Cost		167.7
Total Plant Direct Material and Labor		1,538.0
Percent of Direct Material and Labor for Pollution Abatement		19.9 %

Source: Adapted from Epperly 1981.

[a] Estimates are for a commercial scale plant feed 30,000 tpd (as received) of western Illinois coal.

[b] Includes direct materials and labor costs; excludes indirect charges and process and project contingencies.

available to relate cost differences among liquefaction processes. Rather, published differences seem more related to judgements on what is included as an emission control; and

- No data are available on hydrocarbon emission control costs. This is a critical data shortcoming, because hydrocarbon emission may have the greatest health risk in Lurgi and direct liquefaction process facilities (see Chapter V).

4. Air Quality Impacts and Issues

This section will summarize some of the air quality impacts and issues that would be associated with coal liquefaction plants.[1] These topics will be discussed:

- Ambient air quality impacts of single plants and associated siting issues;
- Regional contributions to emissions from a commercial synfuels industry; and
- Contributions to global CO_2 levels.

4.1 Ambient Air Quality Impacts

a. Criteria Pollutants: There have been a number of studies which have examined, through the use of air pollution dispersion models, the incremental impacts of hypothetical synthetic fuel plants on peak ground-level concentrations of various criteria pollutants. The results can show a wide variation for several reasons, the most important of which are:

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[1] Throughout this section, impact results are based on emissions rates during "normal" operations. Results could change significantly if upset conditions were to occur frequently. As mentioned in the previous section, upsets may occur relatively often in demonstration or pioneer commercial plants, but frequent upsets in commercial plants could not be tolerated. The reason for having demonstration and pioneer commercial plants is to solve the problems so that commercial operations will be smooth.

- Use of different air dispersion models;
- Different locations, which affect meteorological conditions and terrain features;
- Different assumptions and data concerning meteorological conditions;
- Variations in emission rates of the various pollutants; and
- Variations in stack heights.

In addition, all such results are subject to an error range of probably at least ±50 percent due to inadequacies in air dispersion computer models.

Table III.6 presents the estimates for peak SO_2 and particulate concentrations from several studies, representing both direct and indirect processes, under a range of conditions. Also shown in the table are the corresponding PSD Class II and NAAQS standards. Although the results vary over a relatively wide range, an important conclusion is that these facilities apparently will be able to meet the rather stringent PSD Class II increments with planned emission controls. The only exception in the table is the case of rough terrain, where plume impaction causes the PSD Class II 24-hour SO_2 standard to be exceeded by a factor of 13. In the next worse case (i.e., the SRC II commercial-scale plant in West Virginia), 87 percent of the particulate increment and 76 percent of the SO_2 increment are consumed.

Ambient concentrations of NO_x, CO, oxidants, and NMHC are not shown in Table III.4. At the present time criteria pollutants with established PSD increments include only particulates and SO_2; all but NMHC are subject to NAAQS, while a 3-hour "guideline" exists

TABLE III.6: SELECTED ESTIMATES FOR AIR QUALITY IMPACTS FOR LIQUEFACTION FACILITIES UNDER NORMAL OPERATING CONDITIONS

					Emissions (tpd)		Peak Concentration[a] (μg/m³)					
							24-hr. avg. at 25 km		PM		SO_2	
Process (thousands b/d)	Terrain	Stack Height	Location	Sulfur Percent	PM	SO_2	PM	SO_2	ANN.	24-hr.	ANN.	24-hr.
EDS (60)[b]	Flat	Standard stack height	Bristol, TN	3.5	0.9	32.7	0.8	22.0	0.4	4.7	7.3	66.8
EDS (60)[b]	Flat	All stacks at 150m	Bristol, TN	3.5	0.9	32.7	0.3	7.3	0.05	1.2	1.3	32.0
MMG (45)[b]	Flat	Standard	Cheyenne, WY	0.5	0.8	8.0	0.1	1.2	0.03	0.3	0.3	2.5
	Rough	(Max. terrain 448 ft. above plant)	West Virginia	0.5	0.8	8.0	NC	NC	NC	12.9	NC	1,230.0
Fischer-Tropsch (45)[b]	Flat	Standard		0.5	5.4	10.9	1.8	1.4	2.4	14.0	0.3	2.6
	Rough	(Max. terrain 43 ft. above plant)	Illinois	3.5	5.4	10.9	NC	NC	NC	24.0	NC	2.3
EDS (70)[c]	Rough	Standard	Illinois	4.4	1.6	18.6	NC	NC	NC	2.0	NC	35.0
SRC II (72)[d]	Rough	Standard		NC	3.6	7.3	NC	NC	16.3	32.2	6.4	69.2
Synthoil (100)[e]	Flat	Standard	Four Corners	0.7	15.0	14.0	NC	NC	2.6	16.0	3.2	30.0
							Air Quality Standards					
							NAAQS[f]		60.0	150.0	80.0	365.0
							PSD II		19.0	37.0	20.0	91.0

μg/m³ = micrograms per cubic meter
PM = particulate matter
m = meter
km = kilometer
Ann. = annual

[a] Peak concentrations refer to maximum values obtained for worse meteorological conditions expected to occur under stable atmospheric conditions. This does not refer to peaks that might occur during upsets or accidents.

[b] Source: U.S., DOE 1980a, p. 5-13/5-15.

[c] Based on 30,000 tpd coal with conversion fator 2.35 from Appendix Table A-1. Also conversion of tpy to tpd based on 330 days operation. Source: Green 1979, p. 55.

[d] Based on a conversion of 2.42 (14,520 to 6,000) from Appendix Table A-1. Source: U.S., DOE 1980b, pp. C/125/C-131.

[e] Although the Synthoil process is no longer considered a commercial prospect, the results are still useful since emission rates are similar to other direct liquefaction processes. Source: White et al. 1979, Chapter 5.

[f] Most stringent of primary secondary.

for NMHC. Air dispersion modeling results for these pollutants are not as available as for SO_2 and particulates. It appears that NO_x will not be a significant siting concern given current standards. Two studies (White et al. 1979, Vol. 2, and U.S., DOE 1980a, pp. 5-20) indicate that peak annual average concentrations from commercial scale coal liquefaction facilities should equal only 2 to 4 percent of the NAAQS standard. Results for CO are not available; apparently it is not a regulatory concern since its standards are high (e.g., 10,000 ug/m^3 in an 8-hour average) while its emission level is low. The greatest uncertainty surrounds NMHC, as was discussed in the previous section on emissions. Two studies have calculated off-site ambient concentrations of NMHC for single plants of 30,000 tpd coal input as follows:

Plant (size)	Peak NMHS Concentration	Source
EDS	145 ug/m^3 (3-hr. average)	Green 1979, p. 55
SRC II	38 ug/m^3 (8-hr. avg.)	U.S., DOE 1980b, p. C-100[1]

This compares with the NAAQS "guideline" of 160 ug/m^3 (3-hr. avg.). Thus, on this basis, it appears the standard can be met; but, as indicated earlier, the greatest concern is with the possible carcinogenicity of the NMHC releases which is not considered in the basis for NAAQS standard.

In general, it appears that the emission levels of these plants are such that they can meet PSD Class II increments and NAAQS and there are not significant differences among plant types. Nonetheless, air quality may be a serious siting issue for four reasons:

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[1] Scaled from the demonstration plant to a commercial-scale plant.

(1) Many areas, especially in the eastern and interior coal regions, are already nonattainment areas in at least one pollutant. Since coal synfuel plants are relatively large sources of criteria pollutants, finding offsets will likely be difficult;

(2) Whenever a new industrial facility uses a significant part of the PSD II increment, it will preclude other facilities within a "buffer" zone. This means it may be difficult to site several synfuel facilities in the same vicinity and other new sources (e.g., coal-fired power plants) could create large "exclusion zones";

(3) PSD Class I areas will have "buffer" zones around them, which will restrict siting opportunities in several coal areas, especially in the West; and

(4) Air quality regulations are not the only area of siting concern; coal resource availability, water availability, water quality, land use, and socioeconomic effects must also be considered simultaneously. If air quality significantly restricts siting opportunities, the overall effect on siting will be compounded due to the need to satisfy a variety of constraints.

b. Odors: Odors from coal liquefaction and refining operations originate primarily from atmospheric hydrocarbons and reduced sulfur compounds. The odor threshold of potential malodorous compounds in coal liquefaction and refining operations is provided in Table III.7. Like petroleum refineries, H_2S is likely to be one of the major malodorous emissions (MITRE 1981) because of its relative abundance in process streams. The lowest thresholds are for chlorophenol and mercaptans, the later more likely to be an odor problem. The mercaptans are entrained in hydrocarbon process streams, removed in wash solutions, and oxidized in wastewater or gas treatment streams. Emission sources of many of the malodorous chemicals

TABLE III.7: ODORS OF SELECTED COMPOUNDS IN COAL LIQUEFACTION AND REFINING

Chemical	Odor Threshold (ppb by volume)	Odor Description
Acetic acid	1,000	Sour
Amine, monomethyl	21	Fishy, pungent
Amine, dimethyl	47	Fishy
Amine, trimethyl	0.2	Fishy, pungent
Ammonia	46,800	Pungent
Benzene	4,700	Solvent
Benzyl sulfide	2	Sulfidy
Carbon disulfide	210	Vegetable sulfidy
Chlorine	314	Bleach, pungent
Chlorophenol	0.03	Medicinal
Dimethyl sulfide	1 to 2	Vegetable sulfidy
Diethyl sulfide	6	Garlic-like, foul
Diphenyl sulfide	5	Burnt, rubbery
Hydrogen sulfide	.5 to 5	Rotten egg
Methyl ethyl ketone	6,000 to 10,000	Sweet
Mercaptan, methyl	1 to 2	Sulfidy, decayed cabbage
Mercaptan, ethyl	0.4-1	Sulfidy, decayed cabbage
Mercaptan, n-propyl	0.7	Sulfidy
Mercaptan, n-butyl	0.7	Strong, sulfidy
Paracresol	1	Tarry, pungent
Paraxylene	470	Sweet
Phenol	47 to 600	Medicinal
Phosphine	21	Oniony, mustard
Sulfur dioxide	470	Sharp, pungent
Toluene	1,700 to 4,700	Solvent, moth balls

Source: Compiled and modified from MITRE 1981; Cheremisinoff and Young 1975; and NRC 1979.

include fugitive emissions from valve fittings and pumps, venting or flaring, waste treatment ponds, and storage tanks. Data on levels of emissions from coal liquefaction facilities for these specific compounds are not available.

Ranges of estimates of NMHC emissions from liquefaction facilities may act as a guide for assessing the potential occurrences of odors from hydrocarbons and hydrocarbon derivatives. For example, as indicated earlier, NMHC concentrations have been estimated to have peak concentrations of approximately 40 to 150 ug/m^3 (also approximately equivalent to parts per billion by weight at standard temperature and pressure). Threshold detection limits for ethyl mercaptans are about 0.2 to 0.5 parts per billion (by weight). On this basis of DOE estimated fugitive emissions, mercaptans or hydrocarbon derivatives with similar odor properties could be a problem if they represented significant proportions of fugitive emissions.

Hydrogen sulfide, ammonia, chlorine, sulfur dioxide, and phenols levels are relatively independent of nonmethane hydrocarbon emissions. Only sulfur dioxide emission levels have been estimated, and these levels are substantially below odor thresholds.

Based on normal operating performance projections, malodorous air emissions could be potential problems, depending on size of plant and success of directed maintenance programs. Odor emissions episodes outside plant boundaries are well documented from petroleum refineries. Table III.8 documents recorded complaints to several air-quality agencies in California and Texas locations (NRC 1979). These data generally indicate that petroleum related industries account for about 10 to 15 percent of odor complaints in selected Air Quality Control Regions with refineries. Complaints by residents living near refineries include descriptions of repeated annoyance with odors and frequent or occasional dizziness, nausea, vomiting, eye irritation, burning and irritation of the

TABLE III.8: SUMMARY OF COMPLAINTS ON REFINERY ODORS

Location	Time Period	Total Odor Complaints	Refinery Complaints	Other Related Industries
California (South Coast Air Quality District)	1977	1,443	259[a]	262 (industrial)
California Air Resources Board	1975 to 1978	467	18	57 (chemical manufacturing)
Texas				
Houston	September to December 1976	25	3	5 (chemical plants)
Beaumont	September to December 1976	18	2	9 (for chemical plants); 3 (for petrochemical plants)

Source: Based on data in National Academy of Science 1979.

[a] Also includes some chemical industry complaints.

nose, and other symptoms (MITRE 1981). The extent of these kinds of occurrences is apparently related to proximity to population centers, design, and performance of facilities.

4.2 Regional Impacts

This section will examine total contributions to emissions on a regional basis. As a first step, consider the contributions to emissions on a national basis. DOE has estimated 1995 emission levels from all major sources for particulates, SO_2, and NO_x, including emissions from synthetic fuel facilities. The synthetic fuels levels were based on 1995 goals as follows (in b/d equivalent): coal liquids 600,000; gasification, 400,000; oil shale, 300,000; and biomass, 200,000; total, 1,500,000. The results of this projection are given in Table III.9. As indicated, the synfuels contribution is very small; thus, on a national basis for these three criteria pollutants, synthetic fuel plants will not cause a major increase.[1]

On a smaller regional scale, suppose a coal liquefaction industry of one million b/d were developed in the Wyoming, Montana, and North Dakota coal regions (i.e., 20 plants each producing 50,000 b/d). Table III.10 shows, based on typical emission rates, how coal synfuels would increase emissions of four criteria pollutants above 1975 levels. At the present time, these three states are relatively "pristine," with only a few very small nonattainment areas (see U.S., DOE 1980a, Appendix K). Since the percentage increases are relatively small, except for NO_x, incremental regional effects for a rather large synfuels industry would appear to be minimal. The regional effects of NO_x emissions are uncertain, but

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[1] However, one must take into account that in the case of particulates, total emissions in tons is not necessarily a good measure. For example, it is important to make a distinction in particle size, since "fine particulates" are more harmful--but unfortunately such data is not available.

TABLE III.9: ESTIMATED NATIONWIDE EMISSIONS IN 1995
(millions of tons)

Source	Particulates	SO_2	NO_x
Coal-fired power plants	1.23	15.07	8.31
Industrial combustion	0.54	5.87	4.65
Coal conversion plants	0.02	0.20	0.09
Oil shale plants	0.02	0.01	0.11
Other emission sources	10.22	6.98	11.52
Total	12.03	28.13	24.68
Percent synfuels/ total emissions	0.3%	0.8%	0.8%

Source: U.S., DOE 1981a, p. 5-37.

TABLE III.10: INCREASED EMISSIONS FROM A ONE MILLION B/D LIQUEFACTION INDUSTRY IN MONTANA, WYOMING, AND NORTH DAKOTA

Source	Particulates	SO_2	NO_x	HC
Emissions per 50,000 b/d plant (tpd)[a]	5.0	15.0	15.0	7.0
Total synfuel emissions for 1 million b/d (thousands of tpy)[b]	36.5	110.0	110.0	7.3
1975 emission levels (thousands of tyy)[c]	471.0	1,123.0	339.0	438.0
Increase above 1975 due to synfuels (percent)	7.7	9.8	32	1.7

[a] Typical values taken from Table III.2 (page III-19)

[b] Assumed operating at a 100 percent capacity factor.

[c] From NEDS 1975.

they are a precursor to oxidants and to nitrates which can form acid rain.[1]

To take another case, on a still smaller regional scale, a preliminary study has been carried out in Kentucky on potential impacts associated with four proposed commercial-scale coal liquefaction plants which would produce a total of 260,000 b/d of oil equivalent (Enoch 1980).[2] These four plants are all located in a single air quality control region which covers 15 counties in western Kentucky and southern Indiana. Table III.11 shows the estimated emissions from the synthetic fuels plants compared to current levels and projected levels from new power plants being proposed. As described by Enoch:

> The region is currently experiencing problems with total suspended particulates (TSP) and photochemical oxidants (PhO_x). The cities of Henderson and Owensboro and Vanderburgh County, Indiana, are in nonattainment of the air quality standards for TSP; the same areas have had problems recently with PhO_x (measured in ozone). The synfuel plants will cause only a small increase in TSP but the 25 percent increase in hydrocarbon emissions and the 130 percent increase in NO_x emissions may be significant since both contribute to PhO_x formation....
>
> The sulfur and NO_x emissions of synfuel plants and new power plants will be quite an increase over 1976 levels.[3] The standards are not likely to be endangered, however, as the present concentrations of these two pollutants are very low in western Kentucky, in spite of the large amount of high-sulfur coal used there. The resulting increases in sulfate levels will be undesirable

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[1] See Chapter IV for a discussion of acid rain problems.

[2] This study is very preliminary and a more detailed study is under way (Enoch 1980).

[3] Note, however, that by far the greatest increases are due to the new power plants, not the synthetic fuel plants (except for CO and HC).

TABLE III.11: EFFECT OF SYNFUEL PLANTS ON AIR EMISSION IN THE EVANSVILLE-OWENSBORO-HENDERSON AIR QUALITY CONTROL REGION[a]

Emission Sources	Thousands of tpy				
	SO_2	Particulates	NO_2	CO	HC
1976 -Point emissions[b]	263	34	42	88	8
-Area emissions[b]	3	16	15	12	21
-Total[b]	166	50	57	100	29
1976-1992 new power plants	267	20	180	11	3
Total without synfuels	533	70	237	111	32
Four proposed synfuel plants[c]	50	4	74	15	7

Source: Enoch 1980.

[a] Includes Kentucky counties of Daviess, Hancock, Henderson, McLean, Ohio, Union, and Webster; and Indiana counties of Dubois, Gibson, Perry, Pike, Posey, Spencer, Vanderburgh, and Warrick.

[b] U.S., EPA 1979.

[c] Note these emissions data are from Enoch (1980) and do not necessarily agree with the emissions data given in Table III.2. To compare, converting these data to tpd per 50,000 b/d production gives the following: $SO_2 = 26.3$; TSP = 2.1; $NO_x = 38.9$; CO = 7.9; and HC = 3.7.

in view of the present visibility problems they are causing. Furthermore, sulfur and nitrogen emissions are increasingly coming under attack, whether warranted or not, as contributing to interstate pollution and acid precipitation.

Acid rain, visibility, and long-range transport are all very important regional air quality issues associated with high emission levels of criteria pollutants. Certainly, synfuel development can exacerbate these impacts since they do emit significant quantities of criteria pollutants. However, as the above discussion indicates, in general the relative contributions of synfuel facilities will be small--the exception perhaps being NO_x.

4.3 Global Carbon Dioxide[1]

Ambient atmospheric concentrations of CO_2 have increased about 10 percent during the past century, and relationships have been drawn to indicate that fossil fuel burning and deforestation contribute to this increase (U.S., DOE 1980a, p. 5-31). A possible result of these CO_2 increases may be global warming with resultant changes to desert formation, sea levels, and agricultural production. The relative contribution of CO_2 for various fossil fuels compared to crude oil are listed in Table III.12. In the U.S., development of a major synfuels program (4 MMb/d by 2000 and 8 MMb/d by 2025) would increase U.S. CO_2 emmission above present levels by about 3 percent in 1990 and about 7 percent by 2025. This has been projected to increase the global ambient CO_2 concentration by 0.1 percent in 2000 and 0.3 percent in 2025. A world-wide synfuel program (less than double the U.S. program) is projected to increase CO_2 levels in 2025 by 0.5 percent (U.S., DOE 1980a, pp. 5-32 and 5-33). The global CO_2 problem is complex and subject to considerable uncertainty. Nevertheless, several studies have reached similar conclusions such as the following: "CO_2 emissions do not appear to be a major environmental constraint in the development of a U.S. synthetic fuels program" (U.S., DOE 1980a, p. 5-32). However, if CO_2 is perceived to be a major problem in the future, then even small emissions levels could be important to the development of the industry and must be considered in the context of other emission sources and possible control strategies.

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[1] This section is drawn from U.S., DOE 1980a.

TABLE III.12: CARBON DIOXIDE EMISSIONS RATES RELATIVE TO CRUDE OIL

Source	Relative Emission Rate[a]
Natural gas	0.73
Coal burned directly	1.3
Synthetics from coal	1.7
Shale oil[b]	1.7

Source: U.S., DOE 1980a, p. 5-32.

[a] Proportion of carbon dioxide emission relative to thermal energy equivalent of crude oil.

[b] Note that relative emission rates from shale oil are uncertain and are related to yield, process efficiency and deposit characteristics.

5. Conclusions

(a) Although emissions data vary widely, with current information there does not appear to be any basis for distinguishing among the various coal liquefaction processes for criteria pollutants under normal conditions. Emissions rates are more dependent on coal composition and "off sites" (boilers, etc.) than on process technologies.

(b) Fugitive hdyrocarbon emission rates are highly uncertain; however, they are likely to be higher and potentially more toxic in direct liquefaction processes. This is because the direct processes will produce complex aromatic hydrocarbons which are carcinogenic, and the process streams with entrained solids may prove difficult to handle, thus creating higher fugitive emission rates.

(c) Emissions of trace elements could be higher in direct processes, but at the present time there is not sufficient information on their fate.

(d) During "upset" or "emergency" conditions, relatively large emissions of some pollutants (especially SO_2 and particulates) will occur from process streams being burned in the vent/flare system. For example, in the worst case as much SO_2 would be released in two hours as would normally occur in 10 days of operation. Information on the frequency of such upsets is unknown, but they can be expected more often in demonstration and pioneer commercial plants. Because of greater solids handling, direct processes are likely to have more frequent upset conditions. No air quality analyses have been done for upset conditions.

(e) Based on emission rates during normal operating conditions, overall emission of criteria pollutants should be such that meeting NAAQS and the relatively stringent PSD Class II increments should present no major problem in most cases. Emissions of most criteria pollutants from these facilities are much less than from a coal-fired power plant consuming the same amount of coal. Nevertheless, given the complexity of air quality and other environmental regulations, siting these facilities could still prove quite difficult.

(f) Even with relatively high levels of development within a region, in many cases synfuels will not add in a major way to region-wide air quality problems. For example, a 1.5 MMb/d synfuels industry (coal, oil shale, and biomass) would increase nationwide levels of SO_2, particulates, and NO_x, by less than 0.8 percent. Thus, generally, the significance of regional-scale air quality problems will not be highly dependent on the level of synfuels development. (Of course, this conclusion depends on the specific region and the level of synfuels development being considered).

(g) Coal synfuels will release 1.7 times more CO_2 than crude oil, but a large U.S. synfuels program would not increase CO_2 concentrations greatly; for example, according to DOE studies, a production level of 8 million b/d by 2025 is projected to increase concentrations by 0.3 percent in 2025.

C. WATER QUALITY ISSUES

1. Legislative Overview

The Clean Water Act (P.L. 92-500 and P.L 95-217) and the Safe Drinking Water Act (P.L. 93-523) provide for federal and state regulation of water quality. For the synfuels facilities, pertinent standards and controls include:

(1) Effluent standards for industrial discharges established and maintained through a National Discharge Elimination System (NPDES) permit process;

(2) Requirements to use best available technology (BAT) economically achievable;

(3) Special restrictions on discharge to receiving streams that do not achieve ambient water quality targets; and

(4) Protection of groundwater and drinking water systems.

Industrial pollutants have been divided into three classes: toxic, conventional, and nonconventional. Sixty-five toxic chemicals or groups of chemicals have been identified,[1] as listed in Table III.13. Coal liquefaction facilities are potential sources for 20 of these groups. Conventional pollutants include biological oxygen demanding substances, suspended solids, changes in pH, fecal coliform, oil and grease. Nonconventional pollutants are those which are not classified as either toxic or conventional, and include chemical compounds such as nontoxic metals, chlorine, and ammonia. Effluent standards for the pollutant classes have not been established for synthetic fuels facilities. PCGD's discussed earlier are now under consideration and will provide guidance for synfuel facility discharge permit evaluation. Currently, discussion included in draft PCGD's include zero discharge requirement for the 65 toxic chemicals. However, cost and technology may preclude achievement of zero discharge (as discussed in following sections.

In addition to discharge standards, states are required to adopt ambient water quality standards. This system provides for

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[1] EPA was directed by court action to issue water quality criteria for these 65 chemicals (see NRDC v. Train 1976).

TABLE III.13: CLASSES OF TOXIC POLLUTANTS FOR WHICH EPA MUST ISSUE WATER QUALITY CRITERIA

1. Acenaphthene
2. Acrolein
3. Acrylonitrile
4. Aldrin/Dieldrin
5. Antimony and compounds*
6. Arsenic and compounds*
7. Asbestos
8. Benzene*
9. Benzidine

10. Beryllium and compounds*
11. Cadmium and compounds*
12. Carbon tetrachloride
13. Chlordane (technical mixture and metabolites)
14. Chlorinated benzenes (other than dichlorobenzenes)
15. Chlorinated ethanes (including 1,2-dichloroethane, 1,1,1-trichloroethane, and hexachloroethane)
16. Chloroalkyl ethers (chloromethyl, chloroethyl, and mixed ethers)
17. Chlorinated naphthalene
18. Chlorinated phenols (other than those listed elsewhere; includes trichlorophenols and chlorinated cresols)
19. Chloroform
20. 2-Chlorophenol
21. Chromium and compounds*
22. Copper and compounds*
23. Cyanides*
24. DDT and metabolites
25. Dichlorobenzenes (1,2-, 1.3-, and 1,4-dichlorobenzenes)
26. Dichlorobenzidine
27. Dichloroethylenes (1,1- and 1,2-dichloroethylenes)
28. 2,4-Dichlorophenol
29. Dichloropropane and dichloropropene
30. 2,4-Dimethylphenol*
31. Dinitrotoluene
32. Diphenylhydrazine
33. Endosulfan and metabolites
34. Endrin and metabolites
35. Ethylbenzene*
36. Fluoranthene*
37. Haloethers (other than those listed elsewhere; includes chlorophenylphenyl esters, bromophenylphenyl ether, bis(dichloroisoprophy) ether, bis(chloroethoxy) methane, and polychlorinated diphenyl ethers)
38. Halomethanes (other than those listed elsewhere; includes methylene chloride, methyl chloride, methyl bromide, bromoform, dichlorobromomethane, trichlorofluoromethane, dichlorodifluoromethane)
39. Heptachlor and metabolites
40. Hexachlorobutadiene
41. Hexachlorocyclohexane (all isomers)
42. Hexachlorocyclopentadiene
43. Isophorone*
44. Lead and compounds*
45. Mercury and compounds*
46. Naphthalene*
47. Nickel and compounds*
48. Nitrobenzene
49. Nitrophenols (including 2,4-dinitrophenol, dinitrocresol)
50. Nitrosamines
51. Pentachlorophenol
52. Phenol*
53. Phthalate esters
54. Polychlorinated biphenyls (PCBs)
55. Polynuclear aromatic hydrocarbons (including benzanthracenes, benzopyrenes, binzofluoranthene, chrysenes, dibenzanthracenes, and indenopyrenes)*
56. Selenium and compounds*
57. Silver and compounds*
58. 2,3,7,8-Tetrachlorodibenzo-p-dioxin (TCDD)
59. Tetrachloroethylene
60. Thallium and compounds
61. Toluene*
62. Toxaphene
63. Trichloroethylene
64. Vinyl chloride
65. Zinc and compounds*

Source: NRDC v. Train 1976.

*Potential coal liquefaction effluents. Based on a review of compounds found in petroleum refineries and liquefaction plants. Data sources include: MITRE 1981; U.S., DOE 1981a, and b; Braunstein *et al.* 1977; NAS 1979; Ghassemi *et al.* 1979; U.S., EPA 1980a.

classification of stream uses such as drinking water, swimming, wildlife propagation, irrigation, and industrial use. Chemical, physical, and biological criteria are established for these uses. Once these stream-use categories are applied, no further degradation is allowed that would be injurious to the use category. However, for streams and lakes with "outstanding national resources," even small reductions in water quality are not allowed.

To protect drinking water, interim primary drinking water standards have been issued to protect health, and secondary standards have been proposed to protect odor and appearance. The Safe Drinking Water Act protects public drinking water supplies, including aquifers with less than 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) that could become sources of drinking water.

Management of accidental spills to receiving streams are regulated through the Clean Water Act, which requires a Spill Prevention Control and Countermeasure Plan. The plan includes specification of oil storage and transportation equipment and inspection requirements.

2. Water Effluent Levels and Controls

In coal liquefaction plants, wastewater will be produced from most of the plant facilities including:

- Liquefaction process streams;
- Cooling tower and boiler blowdown;
- Coal pile and handling area runoff;
- Ash and slag pile runoff;

- Process area runoff; and
- Sanitary wastes.

The major waste effluent streams are from the stripping and scrubbing of gaseous intermediate process streams for indirect liquefaction, and water separation streams for direct processes. In the case of indirect processes, these cleanup operations can be thought of as transferring potential air pollutants into wastewater streams.

These wastewater streams contain many pollutants that are known to cause health and environmental problems, and therefore they must be controlled. For example, drainage from stored coal piles may be acidic and will contain metals such as lead, chromium, and cadmium. Process wastewaters will contain phenols, ammonia, polynuclear aromatic hydrocarbons, chlorides, sulfates, cyanides, and a variety of trace elements such as arsenic, antimony, cadmium, lead, mercury, and nickel. Tars from cleanup and maintenance operations that may be washed into wastewater contain a range of toxic compounds (pyrenes, phenanthrenes, quinolines, methylindoles, nitrogen containing organics, and sulfur containing organics) (U.S., DOE 1980a, p. 3-13).

To handle those sources of potential pollution during normal operations, wastewater treatment facilities are planned. The treating schemes are "best available technology" (BAT), based on present-day technology used in the electric utility, petroleum, and chemical industries. As indicated in Section A of this chapter, only laboratory and bench scale tests have been performed so far to predict performance of this technology at commercial scale.

The control process which will be used will be combinations of the following steps:

(1) Oil/water separation;
(2) Phenolic compounds (tar acids) recovery;
(3) Ammonia recovery;
(4) pH control;
(5) Primary settling;
(6) Biological treatment;
(7) Mixed media filters;
(8) Activated carbon adsorption;
(9) Reverse osmosis;
(10) Multi-effect evaporation;
(11) Chromium removal; and
(12) Cyanide removal.

The wastewater treatment plants are being designed to provide for recycling of most of the process water. However, uncertainty as to the effectiveness of wastewater treatment technology on trace elements and previously untested mixtures of organic compounds exists.

Assuming that the wastewater treatment technologies function as expected, the quantities of conventional water pollutants estimated to be present in the final effluent during normal operation for the SRC II and EDS processes are listed in Table III.14. These quantities are from a wastewater treatment system designed on the basis that the NPDES permit for a liquefaction plant would be based on

TABLE III.14: ESTIMATED AVERAGE CONCENTRATIONS OF POLLUTANTS IN TREATED COMPOSITE WASTEWATER PROJECTS FOR TWO PLANTS

	SRC II Demonstration Plant (6,000 tpd)[a]		EDS Commercial-Scale Plant (25,000 tpd)[b]	
Parameter	Concentration (ppm)	Discharge Rate (pounds/day)	Concentration (ppm)	Discharge Rate (pounds/day)
BOD	10.0	150.0	10	NA
Total suspended solids	10.0	150.0	<10	840
COD	100.0	1,490.0	50-100	NA
Oil & grease	5.0	75.0	<5	480
Phenol	0.1	1.5	<1	96
Ammonia	5.0	75.0	<1	96
Cyanide (free)	0.15	2.25	NA	NA
Iron	1.0	15.0	NA	NA
Total chromium	0.2	3.0	NA	NA
TDS	3,000.0	44,500.0	NA	NA
Sulfate	1,000.0	15,000.0	NA	NA
pH	6-9.0		NA	NA

BOD = biological oxygen demand COD = chemical oxygen demand

NA = not available

[a] U.S., DOE 1980b, discharge rate 1,238 gallons per minute (gpm).

[b] U.S., EPA 1979b, p. 24; these values represent the design criteria for the EDS process.

the installation of BAT (U.S., EPA 1979b, p. 82). Comparisons between the two technologies included in the table should be interpreted cautiously as neither is based on final engineering designs.

As mentioned above, the treatment systems planned for coal liquefaction plants are based on present petroleum and petrochemical practices. However, two differences may exist between coal liquefaction wastewater and present treatment schemes: (1) presence of polynuclear aromatics (PNA) and (2) trace elements from coal ash. Activated carbon adsorption is used in tertiary water treatment to remove organic compounds which are not digested in biological treatment units. The high molecular weight PNA's should be adsorbed by charcoal beds, but adsorptive capacity may be lower than usual because of large molecular size of the PNA's.

Trace element concentrations are based on estimates from small pilot plant data and therefore are highly uncertain. Table III.15 shows data on the concentration of trace elements in the discharge from the EDS Process (Exxon 1980). More documented information will be obtained from the comprehensive material balance studies which will be made during operation of the larger pilot plants. As a point of comparison, also shown in Table III.15, are recommended drinking water standards. As indicated, some of these trace element concentrations are below the drinking water standard but others are 2 to 10 times higher.

While regulations may allow short-term excess effluent levels from process upsets, control system failures which require longer repair times (e.g., 24 hours) will require plant shut-down unless

TABLE III.15: POTENTIAL CONCENTRATION OF TRACE ELEMENTS IN WASTEWATER DISCHARGE[a]

Element	Concentrations (ppm)	Drinking Water Standards (ppm)
Zinc	1.6	5.0
Copper	0.8	1.0
Chromium	0.5	0.005
Nickel	0.5	--
Tin	0.4	--
Titanium	0.3	--
Lead	0.2	0.05
Manganese	0.05	0.05
Molybdenum	0.04	--
Cadmium	0.02	0.01
Cobalt	0.02	--
Arsenic, mercury, selenium, & vanadium	not deter-ined	

[a] EDS Commercial Design Wastewater and Solids Disposal System Program, Exxon 1980.

provisions have been made for such situations. For example, surges in concentrations of toxic chemicals (phenols, for instance) to biological oxidation units may shock the bacterial colony and reduce (or eliminate completely) its ability to digest the toxic material. Providing surge ponds or multiple parallel processing units may serve to allow plant production to continue, although perhaps at a somewhat reduced level, until process upsets have been remedied.

In the West, wastewaters are expected to be collected and placed in lined evaporative holding and disposal ponds. The sludges that remain after the water evaporates will be disposed of as solid wastes. Thus, in the West, zero discharge of wastewater to surface streams will be the rule. In the East, however, there is uncertainty as to whether regulations will require complete retention (i.e., zero discharge) or whether treated wastewater will be discharged to surface waters. In the East, high rainfall and low evaporation will make zero discharge very difficult. (Seepage and leachates from the holding ponds are discussed in the following section.)

The treatment plans that have been discussed so far are based on normal, steady-state operating conditions. Some provisions are made to handle spills, equipment failures, and excessive rainfall. In order to prevent surface water contamination from rain water runoff, provisions must be made to catch and process runoff from coal piles, operations areas, and the ash/slag disposal areas. Normally, these waters would flow into the wastewater processing system, but during periods of excessive rain, the normal system may be overloaded.[1] Provisions must be made to handle the excess water --perhaps by providing surge-storage ponds to permit processing after rainfall diminishes. Tank or pipeline spills must be collectable on-site. For that reason, operations areas are paved and curbed. The hydrocarbons would be washed down into wastewater systems and separated in the oil/water separative system.

In summary, wastewater streams from coal liquefaction plants have not been fully characterized. To date, it has been assumed that existing refinery wastewater treatment systems can be adapted to the needs of coal liquefaction plants. Water quality is likely to be a serious issue for coal liquefaction plants located in the East since zero discharge will be difficult. In the West, wastewater from coal liquefaction plants will be ponded; water quality problems in this region are related to berm failures and percolation from holding ponds.

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[1] Demonstration facilities are now being designed to withstand a peak 10-year, 24-hour storm without becoming overloaded (International Coal Refining Corporation 1980).

3. Cost of Watewater Treatment

Because commercial designs are not available and because pilot plants currently utilize adjacent refineries for wastewater treatment, performance data for design and costs estimates are incomplete. Available control cost data are also difficult to compare because of varying assumptions such as what levels of control are planned and what constitutes a part of the control system. Indirect processes, for example, cannot operate without removal of acid gases from the product gas stream. This gas removal process controls the "down-stream process environment" for subsequent liquefaction steps, but it is also the first step in isolating contaminants that are directed to the wastewater treatment process. Costs estimates normally do not include this step as wastewater treatment costs. However, this underscores the point that most cost estimates do not clearly separate out what is included in environmental control costs, and thus, comparisons among technologies are especially difficult.

Despite these limitations, Table III.16 identifies some costs estimates for wastewater treatment technologies for selected direct and indirect liquefaction technologies. Indirect processes are

TABLE III.16: REPRESENTATIVE CAPITAL AND ANNUAL COSTS ESTIMATES FOR WASTEWATER TREATMENT (millions of dollars)[a]

Process	Date of Cost Estimate	Capital Costs	Annualized Costs
Indirect			
Lurgi[b]	1980	48	23
Koppers-Totzek[b]	1980	4-12[c]	1.2-4.7
Texaco[b]	1980	2.3-12.7[c]	1-6
Direct			
Exxon Donor Solvent[d]	1978	58.2	NA
H-Coal[e]	1979	30.8-37.5[g]	NA
SRC II[f]	1980	58.6-80[h]	NA

[a] Plant size is "commercial" (50,000 to 60,000 b/d).

[b] Inside EPA 1980b.

[c] Cost variation due to coal type or variation in final liquefaction steps (e.g., Fischer-Tropsch or Methanol-to-Gasoline).

[d] Epperly 1981 (see Table III.5, p. III-34).

[e] Fluor, 1979. Costs include only phenol and ammonia recovery units, costs do not include acid gas removal.

[f] Gulf Mineral Resources 1980.

[g] Cost variation due to differences in Eastern or Western coals.

[h] Cost variation due to variation in process technology included ($58.6 million includes only water reclamation; $80 million includes water reclamation and ammonia and phenol recovery). Plant located in East and fed high sulfur coal.

listed according to gasifier type, which has a significant effect on wastewater control cost.

For the indirect technologies, Lurgi costs are higher according to EPA (Inside EPA 1980b). A Lurgi gasifier would require a phenol extraction unit (through carbon adsorption capable of 99.9 percent phenol removal), a gas stripping system, biological treatment, and vapor compression distillation. The most significant costs are associated with the gas stripping system which removes organic compounds from the wastewater stream. Costs for Lurgi are high because of the wide range of organic materials entrained in process streams which become incorporated in the wastewater streams when the initial gasifier stream (with its hydrogen, carbon monoxide and methane products) is cleaned. Important considerations for Lurgi include:

(1) The largest capital and operating cost items are those for the gas stripping process; the value of the recovered phenol only partially offsets the process costs (Ghassemi et al. 1979);

(2) The cost of ammonia recovery is more than offset by the value of the recovered ammonia;

(3) Biological treatment is a high cost item. The requirement for biological treatment is not necessarily established; if the raw wastewater can be used directly as cooling tower makeup, the use of biological treatment ahead of the cooling tower may not be necessary. This would result in a savings of about 40 percent in total annual cost; and

(4) Wastewater treatment accounts for about 1 to 1.5 percent of the estimated total plant investment of about \$2 billion; the total annual cost is about 0.5 to 1 percent of the total plant annual costs.

Capital costs for H-coal liquefaction have been estimated to range between 30.8 and 37.5 million dollars depending on plant location (Fluor 1979).[1] Wastewater treatment is more expensive for eastern coals than western coals. This is primarily because of a much higher rate of H_2S sour water stripping and higher rates of ammonia throughput required by the wastewater feed. In addition almost three times as much phenol is processed and recovered for Illinois Coal than Wyodak coal.

SRC II wastewater treatment capital costs are estimated to range between 58.6 and 80 million dollars (Gulf Mineral Resources 1980). These costs are for construction in an eastern location for high sulfur coal feed and include all the wastewater reclamation sections; the higher cost (80.8 million) includes ammonia and tar acid recover.

In summary, direct processes and Lurgi indirect liquefaction processes appear to have the highest costs for wastewater treatment. All these processes require phenol separation and handling large quantities of complex organic compounds. Capital costs for these processes range between \$30 and \$80 million out of an estimated total plant cost of between \$1.2 and \$2 billion (1979); thus wastewater treatment capital costs appear to represent about 3 to 5 percent of total plant investment for these processes. Variation in these cost estimates among direct processes probably reflect different economic and technical assumptions rather than differences in environmental control needs.

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[1] The costs estimates for H-Coal may be low because the data source (Fluor 1979) was not specific as to whether wastewater reclamation and treatment costs were charged to other sections at the plant.

Indirect processes based on Koppers-Totzek or Texaco gasification have lower capital costs, typically about $2.3 to $12.7 million. These costs represent about one percent or less of total plant investment.

High sulfur coals increase wastewater treatment costs for both direct and indirect processes. The exact amount is not possible to estimate from the data, but appears to be about a 20 to 25 percent increase in cost for high sulfur eastern coals (e.g., 3.5 to 4 percent sulfur) compared to low sulfur western coals (e.g., 0.7 to 1 percent sulfur).

If zero discharge or near zero discharge goals are to be met, wastewater treatment capital costs in western locations are also significantly lower. Although exact costs differences are not available from the data, apparently about 10 to 20 percent cost reduction is possible if wastewater evaporation and brine concentration facilities are not required. In the West these requirements are reduced relative to the Eastern U.S. because of high evaporation rates and low rainfall.

4. Water Quality Impacts and Issues

The impacts of wastewater discharges and holding ponds of coal liquefaction plants are dependent on the type, number, and sizes of the liquefaction facilities in a drainage area, and the characteristics of the environment, including the extent of existing water pollution levels. Two receiving media are considered in this section: surface water and groundwater.

4.1 Example of Effects on Surface Water in the Eastern U.S.

Along the Ohio River drainage and eastward into the Monongahela River drainage, five coal conversion facilities have been in planning stages (Enoch 1980; U.S., DOE 1980c).[1] Water quality along this river is poor as indicated in Table III.17. Although this water exceeds water quality criteria for some uses such as drinking water, it meets other uses including industrial use, fishing, and swimming. The phenol discharge of up to 0.1 ppm described in the previous section is up to 100 times greater than the ambient water quality standards of .001 ppm for phenols. In addition, for conventional pollutants, the discharge will reduce water quality due to its TDS content of 3,000 ppm.[2] The ambient standard for TDS in the Monongahela River is 500 ppm. It is likely that the NPDES permit for a synthetic fuel plant with this effluent composition will raise serious questions, even though the total amounts by weight, for example, of phenols and dissolved solids are small for a single demonstration plant relative to their content in the river.

Collectively five commercial synthetic fuel plants such as those planned along the Ohio River drainage may contribute significantly to water quality problems. For example, discharges of

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[1] These include Lurgi-Fischer-Tropsch liquefaction; coal-to-methanol liquefaction; SRC I direct liquefaction; SRC II direct liquefaction and H-Coal liquefaction.

[2] West Virginia imposes a monitoring requirement on discharges in excess of 250 ppm TDS and may also require controls for values in excess of 250 ppm (West Virginia, Div. of Water Resources, Industrial Waste Section 1980). Pennsylvania has a limit, for example, of 500 ppm TDS on industrial discharges (U.S., DOE 1980b, p. C-102).

TABLE III.17: WATER QUALITY FOR THE MONONGAHELA RIVER NEAR THE PROPOSED SRC II SITE[a] (mg/l)

Parameter	Range of Values	Percentage of Time Water Quality Criterion[b] Was Not Met	Concentration or Range in Which Ambient Water Quality Criteria Not Met
pH	5.9- 7.9	27	5.6- 5.9
Dissolved oxygen	6.7-14.0	NA	NA
Alkalinity, as $CaCO_3$	3.0-42.0	55	3.0-33.0
Total dissolved solids	162-420	NA	NA
Total suspended solids	<1-81	NA	NA
Biological oxygen demand, 5 day	<1.0-<5.0	NA	NA
Chemical oxygen demand	<5.0-11.0	NA	NA
Total organic carbon	<1.0- 5.0	NA	NA
Phenol	<.001-.005	50	.001-.005
Cyanide	.001-.004	NA	NA
Chloride	6.0-17.0	NA	NA
Sulfate	74-276	9	276
Ammonia-nitrogen	<0.10-0.56	NA	NA
Iron		91	.45-4.3
Manganese		100	.30-.50
Mercury		11	0.2

NA = Not Available

Source: Adpated from U.S., DOE 1980c, p. 3-17 thru 3-23.

[a] Data were taken in 1978-79.

[b] The water quality criteria are the most stringent of those established by EPA, West Virginia, and the Ohio River Valley Water Sanitation Commission Co. U.S., DOE, 1980c, Appendix 5.

phenols if linearly scaled from the SRC II demonstration plant and EDS commercial plant estimates from Table III.14, given previously, could range between 50 pounds to 480 pounds per day.

In both eastern and western U.S. locations accidental spills and flooding can cause serious oil spill incidents (see Section III.C.4.3, following). Spills of naphtha, and light, middle, and heavy distillates can threaten water supplies and damage wildlife populations. Except for the PNA content of heavy distillate fractions,[1] the fate of these spills will be similar to those from petroleum refining and storage facilities.[2] Precautions to limit pollution from flooding areas of the synfuels complex include careful site selection or provision of carefully designed and engineered dikes to meet EPA regulations (40 CFR 112). For example, in the SRC II demonstration plant, bulk product storage tanks will be located above the 500-year flood plain. However, some synfuel facilities such as the Memphis Light, Gas, and Water Division Plant (NCA 1980) is scheduled for construction on the Mississippi River Flood Plain.

4.2 Effects in the Western U.S.

Because western U.S. coal resources are in semiarid regions, the impacts and issues which may develop with the growth of synthetic fuel industry will be different there than in the more humid Interior, Gulf Coast, and Eastern coal resource areas. With climatic conditions which allow rapid evaporation rates, synfuel plants will be able to operate with zero wastewater discharge. Water use will be that consumed in cooling tower and holding pond evaporation. Therefore, routine wastewater discharges from such plants is not expected to be a concern, but the increased consumptive use because of this zero discharge can have an adverse effect on surface water salinity (Ballard, Devine et al. 1980).

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[1] See Chapter V for a discussion of hazards associated with PNA's.

[2] See API, EPA, USCG 1973; and Sittig 1974.

Since surface water salinity is a major concern in western states, particularly in the Colorado River basins, withdrawal of water to operate synfuel facilities can often increase salinity by removing water which serves to dilute salt concentrations downstream. For example, one study estimated the effect of two coal-fired power plant units totalling 760 megawatts (MW) planned near Craig, Colorado. These two units would consume 12,000 AFY and were estimated to result in an average salinity increase of 0.7 mg/l below Hoover Dam (U.S., DOI, BLM 1976, pp. III-3 through III-9). Another study estimated that a 410 MMcfd coal gasification development in the Four Corners region of New Mexico consuming 15,000 AFY from the San Juan River, would increase salinity about 2.4 mg/l at Imperial Dam (U.S., DOI, BuRec 1977). Although these increments are small compared to existing salinity levels of 600 to 800 mg/l, energy development is likely to intensify conflicts over salinity control, and thus energy production could be constrained by salinity standards if adequate controls are not established. Federal efforts to control salinity in the Colorado River Basin (CRB) have already been subject to delays and cost increases, and states of the CRB have been criticized by some groups for failure to establish a comprehensive, authoritative, and enforceable salinity control program (Ballard, Devine et al. 1980). This problem can be minimized or, water quality can even be improved, by using saline waters (ground or surface depending on the site) in place of fresh surface water for plant process purposes (Ballard, Devine, et al. 1980).

Holding ponds will be used for retaining liquid effluents from coal conversion facilities in the West (and in some cases in the East), allowing the water to be evaporated. However, wastes can leave the holding pond and become environmental problems through evaporation, wind erosion, seepage, leaks, accidental berm failures and pond overflow (Gavande, Holland, and Collins 1978). Some waste pollutants from holding ponds are released to the air along with eavporated water. These include H_2S, methane, ammonia, and other nitrogen gases. Contamination of areas immediately adjacent to the holding pond can occur by wind-whipped spray if the wastes are in liquid form, or by wind erosion of dried wastes in the holding pond. Seepage from the holding pond, which is likely to contain nitrates, chlorides, sulfates, boron, and cyanide, can move through the soil to adjacent groundwater systems (Gavande, Holland, and Collins 1978). If the holding pond leaks, both dissolved and suspended materials in the effluent may flow into the underground water system. Also, heavy rains or a period of decreased evaporation rate coupled with a heavy rate of effluent inflow into the holding pond can cause pond overflow and subsequent pollution of surface or groundwaters. The amount of seepage is highly dependent on location and there is no available data on potential rates of loss from synfuel holding ponds. However, some data is available on the composition of leachates of solids and sludges from the ash, slag, and wastewater treatment process, which are discussed in the following section on solid wastes.

4.3 Product Transport Accidents

Potential water pollution incidents may occur from the transport of coal liquefaction products by pipe, rail, and trucks. Some products will be shipped relatively short distances (less than 100 miles) to nearby refineries, while others will be shipped much longer distances by rail, truck, or pipeline. For example, fuel oil fractions from the SRC II facility are expected to be shipped by rail. Each month, the demonstration plant would use about 12 unit trains, each containing 63,000 tons, for shipping the fuel oil. Based on extrapolation from spills of hazardous commodities, this data source suggests that a "reportable" spill[1] would be expected to occur every 1.3 to 2.8 months. Spills over bodies of water would be expected to occur once every 30 to 60 months (U.S., DOE 1981). (Because of the larger scale, one commercial-scale plant would have about 5 times higher probability of spills than would the demonstration plant). The transport of products is essential to the coal liquefaction fuel cycle and measures to minimize spills along transportation corridors may be an important environmental issue.

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[1] A "reportable" spill is one for which losses in value or to property exceed $2,900 (U.S., DOE 1981).

5. Conclusions

Water quality impacts from coal liquefaction are important issues affecting both environmental interests and developers. Important conclusions are:

(1) EPA has concluded there are substantial differences in wastewater treatment requirements, both between and among direct and indirect processes. For example, indirect processes based on Lurgi would have considerably higher capital and operating costs than a facility based on Koppers-Totzek or Texaco;

(2) Reliable estimates for the composition of wastewater discharges have not been completed for either demonstration or commercial plants;

(3) Developers expect that (under normal operating circumstances) application of electric utility and petrochemical industry wastewater treatment technology will result in predictable effluent concentration for "conventional" pollutants; however, the presence of trace elements and toxic organic compounds introduces uncertainty in the ability and cost of controlling effluent discharges to acceptable levels;

(4) Substantial disagreement and uncertainty now exists on the anticipated composition, duration, and extent of effluents that leave the plant boundary due to design uncertainties. Some process designers claim very low discharge rates (e.g., SRC I) and others claim lower flows for commercial plants than demonstration plants (e.g., SRC II). The design uncertainties are not likely to be resolved until commercial plants operate;

(5) Generally, direct processes pose more uncertainty and greater potential for water quality degradation than indirect processes. This is primarily because of the greater uncertainty in trace element segregation, the potential for plant upset with high ash process streams, and the abundance of PNA's;

(6) The East will be exposed to greater water quality risks than the West from coal liquefaction plants. This is primarily related to the size of effluent discharges and the

frequency of flooding in the East. In addition, the low sulfur and high oxygen content of western coals makes the riskier direct liquefaction processes more economically suitable in the East;

(7) Even where there are low or zero discharge rates, such as in the West, there are risks to surface and groundwater from holding ponds. These risks are difficult to quantify and can come from long-term seepage or from breaks and flooding. Once groundwater is polluted it is, to a large extent, irreversible; and

(8) Transportation accidents pose a potentially significant risk to streams. If large portions of products are shipped by rail, some data suggests that reportable spills from a single commercial plant could be as frequent as about once a week.

Alternatives can be explored to balance the environmental and cost trade-offs that will result from synfuels development, including:

(1) Provide for early demonstrations of the candidate control technologies in order to obtain better data on the environmental and economic costs of alternative processes;

(2) Provide for additional impoundments to maintain water quality and flow;

(3) Provide for greater use of on-site wastewater storage to reduce discharges during low or poor quality stream flow conditions;

(4) Provide for increased water treatment, such as ion exchange systems to reduce dissolved solids content;

(5) Provide for additional evaporation capacity through the use of heated evaporators, (although this would lower process efficiency);

(6) Provide for exemptions to some NPDES permit requirements to allow "selected" discharges--selected in terms of both composition and time. This approach would utilize the assimilative capacity of existing streams to dilute or degrade pollutants; and

(7) Provide for careful site selection, including utilization of saline water sources for some plant requirements.

D. SOLID WASTE ISSUES

1. Legislative Overview

Disposal of solid wastes from synfuels facilities will be primarily regulated through provisions of the Resource Conservation and Recovery Act of 1976 (RCRA). This legislation requires:

(1) Specification of management procedures and control technology for all solid waste facilities;

(2) Identification of hazardous wastes and the specification of special containment and monitoring requirements for hazardous waste generators, transporters, and disposal facilities; and

(3) Restriction on siting hazardous waste facilities to exclude wetlands and flood plains and other areas.

In a synfuel plant, all material outputs are regulated through RCRA except saleable products, effluents controlled by a NPDES permit, and gaseous emissions. To determine if materials are hazardous they are tested and evaluated against biological and chemical criteria as required by the Act. If classified as hazardous, then siting restrictions, containment, and monitoring provisions apply that would both restrict facility location and greatly increase costs of synfuels facility operations.

Solid wastes from surface mining including overburden handling and coal cleaning operations are regulated by the Surface Mine Control and Reclamation Act of 1977. This Act provides for a system of solids handling, revegetation, and monitoring. Mine related legislation, impacts, and issues are not described here; for information see the OTA report "Direct Use of Coal" (U.S., Congress, OTA 1979). However, selected impacts related to land disturbance from mines are briefly summarized in Chapter IV on ecological impacts.

2. Solid Waste Control Technology and Residuals

All coal conversion processes produce considerable quantities of ash. Air and water pollution controls also capture potential air and water pollutants. These pollutants along with the additives designed to react with them and solidify them become part of the solid waste stream. These solid waste streams are often toxic and/or hazardous.[1] Thus, the air and water pollution controls described earlier cause a large increase in the quantity of solid waste as well as an increase in their toxicity. In fact, the amounts are staggering--on the order of 10 to 30 percent of the volume of the coal feed (U.S., DOE 1980a, p. 3-9). A 50,000 b/d per day liquefaction facility will generate about 30 million tons of waste over its 30 year life (U.S., DOE 1980a, p. 5-78).

Sources of solid wastes which must be dealt with in an environmentally aceptable way are:

(1) Ash or slag from gasifiers generating either hydrogen or gaseous fuel (this ash is produced in a reducing atmosphere and contains organic compounds);

(2) Ash-bottoms and fly ash from coal-fired boilers (this ash is produced in an oxidizing atmosphere and contains primarily mineral matter);

(3) Flue-gas desulfurization sludge from coal-fired boilers (consists of calcium sulfate and other salts);

(4) Sludge from biological treatment, containing organic and inorganic compounds;

(5) Sludge from raw water clarifiers;

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[1] Hazardous materials pose a risk to health and property and may be toxic (poisonous), explosive, corrosive, etc. Toxic materials produce adverse health effects, typically even in small amounts.

(6) Spent activated carbon; and

(7) Spent catalysts, including a variety of metalic compounds. Of those sources of wastes, the largest quantities are ash/slag (i.e., items 1 and 2 above). A coal containing 10 percent ash, fed at a rate of 30,000 tpd, will produce 3,000 tpd of ash or slag.

Table III.18 summarizes available data on solid waste amounts generated by five types of coal liquefaction technologies. Variations among wastes are due primarily to differences in ash content and composition of coals, process efficiency, and air and wastewater control technology. The first group of wastes in Table III.18 includes material that was originally part of the coal feed --ash from the gasifiers and auxiliary boilers and possibly unreacted carbon in the form of chars and tars from direct liquefaction.[1] Mineral matter and unreacted carbon is variously termed slag, flexicoker residue (in the case of the EDS process), or vacuum tower bottoms (in the case of the SRC II process). As indicated in Table III.18, four of the five technologies (operating at the level of 50,000 b/d) produce about 2,000 tpd of this kind of waste. According to the data (based on pilot plant studies), the SRC II process produces much more of this type of waste than the others. However, most of the 4,000 to 7,000 tpd produced from the SRC II process is residue from the liquefaction reactor. While it is mostly ash, this residue does have a high carbon content and thus a relatively high energy content. Methods for recovering that

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[1] Chars and tars in direct process commercial plants are expected to be fed into gasifiers for hydrogen generation. However, some chars may be disposed of (U.S., EPA 1979b, p. 253).

TABLE III.18: ESTIMATES OF SOLID WASTES FROM COAL LIQUEFACTION PROCESSES
(tpd for a 50,000 b/d facility)

Process	Coal Waste (ash, slag, chars)[a]	Catalysts, Reactants and Sludges[b]
Indirect		
MMG	1,800-2,000	NC
Fischer-Tropsch	1,800-2,000	>75
Direct		
Exxon Donor Solvent	1,850-3,000	2,300
H-Coal	2,200	820
SRC II	4,000-7,000[c]	>45

NC = Not Considered

[a] Coal wastes include the waste generated directly by the process that is part of the original coal feed such as slag or ash and unreacted carbon.

[b] Includes secondary added materials and chemicals such as catalysts, lime from scrubbers and added reactants from water treatment. Most of these waste materials are in the form of sludges.

[c] Includes some unreacted organic compounds and carbon that would probably be recovered in a commercial plant.

useful energy are planned for commercial facilities. When this residue is used as boiler fuel or as a gasifier feed for hydrogen generation, the ash type wastes from direct liquefaction process would be similar or slightly less than those from indirect technologies, depending on overall process efficiency (Sections II.D and E). Ash and slag wastes contain portions of the trace elements that are in the coal feed, including arsenic, barium, cadmium, chromium, lead, mercury, selenium, silver, copper, nickel, and zinc (U.S., DOE 1980a, p. 3-9).

Wastes in the second group (Table III.18) consist of secondary added materials and chemicals such as catalysts, lime from scrubbers, and added reactants from water treatment (see Table III.19 for potential chemicals). These will include the FGD sludges and the wastewater treatment sludges from oil/water separation, chemical precipitation, and biological oxidation. The treatment of wastewaters to meet BAT requirements normally produces sludges containing various levels of toxic pollutants. These types of sludges are defined as hazardous waste under Section 3001 of RCRA (U.S., EPA 1979b, p. 100). The quantity of these wastes tabulated for the EDS process (2,300 tpd) is much larger than that from the other technologies because FGD sludge is included. The sludge from the H-Coal plant is known to contain oil and grease and chromium (U.S., EPA 1979b, pp. 47-52). For a 50,000 b/d H-Coal plant, this sludge will be produced at a rate of 800 tpd which is 97.5 percent of these secondary solid wastes, the remainder being spent catalyst.

Most of the solid wastes from these chemical groups would be deposited in a landfill. Details of landfill design for a commercial plant are not available. Generally, the boiler wastes blended with clay would form a comparatively impervious layer placed on top of a clay liner. The gasifier or any direct process reactor wastes would be compacted over the boiler wastes. A 30-year plant-life would require about one square mile of land with waste piles fifty feet high deposited in four working areas (Green 1979). About two feet of soil would be placed on top of the pile and be revegetated. The area would be isolated from external runoff and would employ

TABLE III.19: COAL CONVERSION CATALYSTS AND CHEMICALS POTENTIALLY IN SOLID WASTES

Catalysts and Chemicals	Use
Activated carbon	Purification
Iron Oxide	Purification
Methanol	Purification
Propylene carbonate	Purification
Sodium carbonate	Purification
Potassium carbonate	Purification
Amines	
Monethanolamine	Purification
Diethanolamine	Purification
Diglycolamine	Purification
Cobalt-molybdenum	Shift conversion, liquefaction (hydrotreating), purification
Limestone-dolomite	Sulfur recovery
Nickel	Methanation or liquefaction
Vanadium	Sulfur recovery
Dolomite	Purification
Bauxite	Sulfur recovery
Isopropyl ether	Phenol recovery
n-Methyl-2-pyrrolidine	Purification
Dimethyl ether polyethylene glycol	Purification
K_3AsO_3	Liquefaction
Tungsten	Liquefaction
Zinc chloride	Liquefaction
Sodium sulfite	Purification
$CO\text{-}Mo/SiO_2\text{-}Al_2O_3$	Liquefaction
Sulfoxide	Sulfur recovery
Chelated iron salt	Sulfur recovery
Nickel-tungsten	Liquefaction (hydrotreating)

Source: Braunstein, Copenhaver and Pfuderer 1977.

some type of leachate collection system. Monitoring the waste pile would be required. Environmental control practices following "decommissioning" the plant have not been specified (e.g., see U.S., DOE 1980c).

3. Solid Waste Impacts and Issues

As indicated earlier, solid wastes disposal technology for coal liquefaction facilities must handle large quantities of wastes, which may be classified as hazardous. A number of environmental issues have been raised about the potential impact and adequacy of solid waste control technology. These issues include:

(1) Are solid wastes sufficiently toxic to pose a hazard from airborne dust or leaching to ground and surface waters;

(2) Are control technologies adequate to provide environmental protection at aceptable costs; and

(3) Is the magnitude of solid waste from a synfuel industry so large as to create significant disposal problems and associated land use issues on a regional basis?

3.1 Toxicity of Solid Wastes

A primary reason that ash and slag may pose a hazard is that trace elements in coal become concentrated and released from the solid organic coal matrix during coal combustion, pyrolysis, or coal combustion, pyrolysis, or hydrogenation. For example, arsenic, chromium and other trace elements are concentrated as can be seen in Table III.20 which compares coal to ash-slag waste off the vacuum bottoms of the SRC II process.

If these trace elements are stabilized within a landfill, the issue of environmental impact is minimized. However, water percolating through a landfill may leach these materials from the disposal site and contaminate groundwater. Leachate tests of EDS flexicoking tertiary fines and and ash-slag waste off the vacuum bottom of SRC II pilot plants are shown in Table III.21. These indicate that inorganic materials in leachates meet RCRA Criteria

TABLE III.20: SELECTED ELEMENTS PRESENT IN FEED COAL AND ASH/SLAG (SRC II Process)

Element	*Feed Coal*[a]	Ash/Slag
Arsenic, ppm	7	46
Barium, ppm	57	310
Calcium, %	0.82	2.26
Cesium, ppm	1	7
Chromium, ppm	21	708
Cobalt, ppm	1.4	36.8
Copper, ppm	<60	<300
Iron, %	1.17	15.8
Magnesium, ppm	0.16	1.3
Manganese, ppm	11.0	274
Molybdenum, ppm	10	63
Potassium, %	0.258	1.9
Selenium, ppm	3.0	17
Silver, ppm	--	<10
Sodium, ppm	349	2,350
Strontium, ppm	38	170
Thorium, ppm	1.4	14
Titanium, ppm	693	4,590
Vanadium, ppm	90	457
Uranium, ppm	1.54	18

Source: U.S., DOE 1981.

[a] Oak Ridge National Laboratory sample of Western Kentucky No. 9, not necessarily representative of actual feed coal producing the ash/slag.

of 100 times the drinking water standard, and would not be classified as toxic according to this procedure.

However, ash produced in reducing atmospheres[1] may have complex organic compounds present. For example, the slag from a Texaco medium-Btu gasifier that was fed ash off the vacuum bottoms of the SRC II process has been found to contain small quantities of PNA's. The results of benzene extraction of slag are shown in Table III.22. These concentrations would not likely be reached under

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[1] Reduced atmospheres are typically without oxygen. Compounds such as hydrogen gas and carbon monoxide are present.

TABLE III-21: LEACHATE COMPOSITION[a] (ppm)

Substance	EDS Flexicoking Tertiary Fines: Illinois Coal	EDS Flexicoking Tertiary Fines: Wyoming Coal	SRC II Vacuums Bottoms Kentucky Coal	EPA/RCRA Criteria For Being Hazardous[b]
F	0.3	3.3	NA	
NO_3	<3.0	NA	NA	1,000.0
Ag	<0.002	<0.004	0.00007	5.0
As	<0.06	<0.1	0.0005	5.0
Ba	1.8	0.2	<0.5	100.0
Cd	0.04	<0.01	0.0034	1.0
Cr	0.004	<0.002	0.00013	5.0
Hg	0.0004	0.0006	0.0002	0.2
Pb	0.05	<0.08	<0.0002	5.0
Se	<0.04	<0.07	0.001	1.0

NA = Not Available

Source: Green 1980; U.S., DOE 1980b.

[a] Using 12/12/78 EPA toxicant extraction procedure.

[b] Criteria have been set at 100 times the EPA Primary Drinking Water Standard.

TABLE III.22: BENZENE EXTRACTION OF SRC II SLAG

Constituent	Coarse Slag	Fine Slag
Total benzene solubles (percent by weight)	0.0315	0.0165
Benz-a-anthracene (ppb)	12	10
Benz-a-pyrene (ppb)	17	13
Benz-e-pyrene (ppb)	4	17
Benzo (g,h,i) perylene (ppb)	8	5

ppb = parts per billion

Source: U.S., DOE, 1981.

landfill conditions, as these materials are much less soluble in water. If vacuum bottoms or other high organic fractions are fed to boilers (with an oxidizing atmosphere) significantly lower levels or organic constituents would occur.

Whether the small concentrations of organic materials will leach into groundwater and pose a health risk is difficult to predict. EPA has yet to determine which fractions of coal liquefaction solid wastes may be classified as hazardous or as special wastes (such as boiler ash). A recent symposium on biomedical and ecological considerations of coal conversion indicate that some authors believe that gasified SRC II mineral residue is "nonhazardous" under RCRA criteria" (DeCiceo 1980). Yet a secure landfill has been proposed for disposal of the wastes, utilizing base soils of low permeability with an ability to attenuate contaminants. Uncertainties remain however, and it is possible that the issue of solids waste toxicity will not be resolved until commercial plants have been monitored over extensive time periods.

3.2 Costs and Adequacy of Control Technology

As indicated above, coal ash produced in reducing atmospheres may be considered more hazardous than ash from boilers. However, inadequate information is available to indicate whether a measurable health risk exists. If wastes are classified as hazardous, significant increases in costs are likely to be incurred primarily because of the special handling required and the need for long term security.

A 1978 estimate of cost for solid waste disposal of ash and sludges placed in pits, ponds, and landfills was about \$2.00 a ton.[1] However, solid wastes disposal is estimated to increase up to about \$10 per ton for nonhazardous wastes, to comply with existing existing regulations. For hazardous wastes, estimates for the cost of secure disposal that represents a very low risk for environmental contamination are about \$90 a ton (EPRI Journal 1978). However, as indicated in the previous section, these costly controls may not be incurred for most of the solid wastes at a coal liquefaction facility.

Solid waste disposal cost estimates are not available for most coal liquefaction plants. These costs are highly dependent on ash content, haulage distance, and design characteristics for specific sites. However, the discussion below identifies some cost considerations for Lurgi and H-Coal synthetic fuel facilities.

For a complete Lurgi facility with on-site electricity and steam generation, the cost for landfill disposal of power plant fly ash and FGD sludge has been estimated at about \$12 per ton (\$11 per dry ton--1978 dollars)(Ghassemi et al. 1979). The ash disposal costs for Lurgi plants located at the mine mouth, such as proposed in western locations, should be somewhat less because a portion of the costs would be incurred in the mine reclamation costs.

If chemical fixation of wastes is needed to reduce the mobility of contaminants, these costs estimates would increase. Chemical fixation[1] can reduce solubility and chemical reactivity. Chemical fixation might be expected to add about $1 to $3.70 (1978 dollars) to the cost of fly ash/FDG sludge disposal (Ghassemi et al. 1979). The total annualized costs of solid waste management for a Lurgi facility would be about $18 to 30 million for coal contents in the range of 7 percent to 20 percent ash.[2] This represents about 3 percent to 5 percent of the total annual operating cost.

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[1] Estimate for the ash, bottom ash, sludges, and other wastes from coal-fired boilers. EPRI Journal 1978.

H-Coal conceptual engineering studies have indicated the operating costs for disposal of ash are $4/dry ton with a 90 percent operating factor and disposal of 569,000 tons of ash per year (Fluor 1979). These cost estimates now appear low. Overall costs in the H-Coal study are sensitive to ash content to coal. In the case of H-Coal, the lower ash content of some western coals results in a lower solid waste disposal volume, and lower cost per million Btu's of product compared to a higher ash content eastern coal.

Solid wastes disposal cost estimates thus vary widely. Important factors affecting costs include:

- Ash content of coal and process efficiency. Direct processes using low ash content coals have the lowest disposal volumes.
- Disposal costs are most sensitive to technical requirements for ash disposal. Solid waste disposal costs can range between $4 per ton and $90 per ton or more. Ash with lowest organic content from oxidizing atmospheres (such as boilers) can have the lower disposal costs. Catalysts or sludges with heavy metal and polynuclear organic hydrocarbons would require more costly disposal practices.

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[1] Also referred to as cementation, waste passification, or waste immobilization.

[2] As estimated from a Lurgi synthetic natural gas facility.

RCRA regulations affect costs by restricting locations where hazardous waste sites can be located. Locations to be avoided include:

(1) Wetlands areas;

(2) Flood plains;

(3) Critical habitat for endangered species; and

(4) Fault zones.

In addition, design must isolate the disposal sites from groundwater, and provide a continuing monitoring system for landfills that have potential for discharge into usable aquifers.

In summary, several problems underly solid waste disposal:

(1) The degree of environmental hazard of coal liquefaction wastes disposal methods is dependent on both processes and location, and is uncertain at the present time;

(2) Disposal costs are highly dependent on the outcome of the classification as to the degree of hazard; and

(3) If significant volumes of solid wastes are classified as hazardous, disposal operational costs would increase from about 1 to 2 dollars a barrel[1] of liquids produced to 10 to 20 dollars per barrel.[2]

This latter figure, although unlikely, would place a significant burden on the coal liquefaction industry.

3.3 Areawide Waste Disposal

Synfuels projects anticipated for Kentucky and West Virginia provide an example of the magnitude of the solid waste disposal problem for a region. The five synfuel plants will produce approximately 15,000 tpd of solid waste, or, in volumetric terms, about 2,500 AFY (Enoch 1980). If solids were piled to a depth of about 50 feet, the five plants would require about 70 acres per year. However, somewhat larger surface areas will be required in practice during initial plant development. Most disposal sites would be located within or adjacent to plant property, or in mines in some cases.

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[1] Based on the assumption of 1 to 2 tons of solids disposal per 10 barrels of oil produced at a cost of $10 per ton for solid wastes disposal.

[2] Based as above, but with disposal costs of $50-100 per ton (see EPRI Journal 1978, pp. 36-41 and 1980, p. 18).

As a basis of comparison, this amount of land use for solid waste disposal is significantly less than that for mines and overall plants. Each plant will occupy 1,000 to 2,000 acres of land (Enoch 1980). In Kentucky alone, an estimated 40 million tons of coal a year to supply four of the plants would disturb about 4,000 acres per year.[1] On the basis of this comparison, the area disturbance of landfills from synfuels facilities is much smaller, about four percent, compared to the disturbances resulting from mining.

The environmental disturbances posed by solid wastes are primarily related to the adequacy and cost of control technology and the security of sites. Of special concern would be areas located in close proximity to groundwater tables, or subject to wind or water erosion. In the Western U.S., long term stability of wastes piles in arid or semiarid locations is likely to be an issue. In the Eastern U.S., proximity of disposal sites to rivers or flood plains is an issue. Importantly large areas of two of the proposed synthetic fuels demonstration plants are planned on flood plains: one at Newman, Kentucky[1] and one at Memphis, Tennessee.[2] Physical integrity of the plant area is a critical design requirement to minimize risk of losing security of a solid waste disposal site during floods.

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[1] Based on a coal supply with 50 percent from surface mining, 1,800 tons coal/AF, 45 inch sections, 80 percent recovery and 10 percent additional area used for haul roads, prep plants, etc. (Enoch 1980).

4. Conclusions

The multiple solid wastes streams from coal liquefaction facilities contain a wide range of organic and inorganic pollutants, some of which are toxic according to RCRA criteria.[3] Some solid wastes from both indirect and direct processes are likely to be classified as hazardous and incur costly handling and disposal practices. Some of the important choices and variables affecting solid wastes issues are:

(1) The toxicity of primary solid wastes (the ash stream) is largely dependent on the final step in ash processing. For indirect processes this step is gasification. In the direct process the waste is from one or more steps:

   (a) a high organic content ash ("bottoms") from the product separation step; or

   (b) a gasification (or flexicoker) step; or,

   (c) a boiler (for steam or electricity).

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[1] SRC I plant is sited on a riverside area subject to floods.

[2] The Memphis Power and Light demonstration plant is located on the flood plains of the Mississippi River (several other synfuel plants are located partially on flood plains).

[3] Actual testing and evaluation is conducted by plant sponsors and developers.

"Bottoms" are most hazardous, followed by gasifier ash. Boiler ash is least hazardous. Although pilot plants have been disposing of "bottoms" as solid solid waste, it is expected that demonstration and commercial plants will gasify or burn this ash fraction.

(2) Siting criteria for hazardous waste disposal facilities apparently have not been followed for two large-scale demonstration plants. In these cases, land acquisition has proceeded for coal synthetic fuel facilities with large areas on flood plains.

(3) The land areas required for process solid waste disposal are small compared to other land requirements in the complete coal synthetic fuel cycle.

(4) Like air and water problems, the solid waste disposal issue is closely related to location. Soil type, proximity to aquifers, and flood characteristics are likely to be more important than differences among process technologies in affecting impacts.

(5) The volume of solid waste is most closely related to overall process efficiency and coal type. To some extent this contrasts with air and water pollutants whose emission and effluent levels can be set on the basis of control technology and design standards. Higher ash coals, especially lignites, will have the largest volumes of solid wastes. These "reactive" coals, including subbituminous coal and lignite, are also suitable for the less efficient indirect processes. Thus, the indirect liquefaction processes fed lignite or higher ash subbituminous coals will have significantly more ash handling than those processes using coals such as eastern bituminous.

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CHAPTER IV

ECOLOGICAL AND LOCATIONAL ISSUES

A. LEGISLATIVE OVERVIEW

In addition to the direct effects coal liquefaction plants have on the receiving media from air emissions, water effluents and solid wastes discussed in Chapter III, the mines, processing facilities and transportation systems change land use and alter habitat that influence the distribution of plant and animal communities. These ecological changes are the subject of a number of federal statutes including those identified in Table IV.1.

For federal lands use, the effect of this legislation is to require detailed evaluation of land development alternatives by the departments of Interior and Agriculture for long term planning and management. For some state and private lands, control on development of selected land areas is required: for example, the Coastal Zone Management Act and the Endangered Species Act require protection of land use values and prohibitions against uses such as synthetic fuels plants or coal mines that would infringe on these protected values.

Generally, government's role in wildlife management is on a cooperative management basis among state agencies and federal agencies such as the Fish and Wildlife Service and Forest Service. Some legislation, such as the Bald and Golden Eagle Protection Act

TABLE IV.1: SELECTED FEDERAL STATUTES CONTROLLING ECOLOGICAL IMPACTS

Federal Statutes	Jurisdiction	Selected Protective Provisions
Soil and Water Resources Conservation Act of 1977	Nationwide through Department of Agriculture	Develops a program of soil and water protection
Surface Mine Reclamation Act of 1977	Nationwide through Department of Interior	Establishes reclamation standards and procedures
Federal Land Policy Act of 1976	Public lands under Bureau of Land Management (BLM) jurisdiction	Develops multiple use for land-use plans
National Forest Management Act of 1976	National Forest and Grasslands under Department of Agriculture	Develops multiple use land-use plans
Coastal Zone Management Act of 1974	The coastal zone as defined by states	Establishes planning and permitting procedure for public and private coastal lands
Endangered Species Act of 1973	Nationwide to selected areas of critical habitat determined by the Department of Interior	Prohibits federal development on areas identified as critical to endangered species
Fish and Wildlife Act of 1956 (16 U.S.C. 742-754)	Nationwide cooperation with states and enforcement of U.S. Fish and Wildlife Service	Develops policies and procedures for fisheries and wildlife resources
Wild and Scenic River Act of 1968	Selected stream segments protected by Department of Interior	Identifies and preserves streams for selected recreational areas
Wilderness Act of 1964	Identification of public lands for limited access by Department of Interior	Prohibits development on selected public lands
Protection of Bald and Golden Eagle Act of 1962	Nationwide protection of eagles through Department of Interior	Prohibits destruction of eagles
Soil Conservation Act of 1935	Nationwide, supported by the Department of Agriculture	Establishes local conservation districts and technical support

as well as the Endangered Species Act provides for protection of species and habitat essential for their perpetuation. However, it should be recognized that no single act provides for complete preservation of natural ecosystems and their associated wildlife, although wilderness acts have set aside large parcels of land for this purpose. The National Environmental Policy Act provides for assessment of the changes of individual or programmatic federal action on the environment, and the enabling acts for the Fish and Wildlife Service provide for assessment of the status of wildlife population and their habitat. However, the continuing change to most ecosystems from cumulative industrialization and population growth is not protected, and it is an area difficult to measure or assess and assign responsibility for control or corrective actions.

B. CONDITIONS AFFECTING ECOLOGICAL IMPACTS

Table IV.2 describes conditions contributing to ecological impacts and indicates how these impacts are affected by regional differences in these underlying conditions. The thickness of coal seams, for example, results in more land disturbances in the East than in the West as discussed below. The sulfur and ash content of the coal also affects the extent of air and solid waste impacts which were discussed in Chapter III. Population density and the composition and character of existing ecosystems are also important.

Ecological resources are generally defined to include both natural (terrestrial and aquatic) ecosystems as well as agricultural

TABLE IV.2: REGIONAL CONDITIONS AFFECTING ENVIRONMENTAL IMPACTS

An EXISTING CONDITION	Determines an INTERMEDIATE EFFECT	Which partially determines an ENVIRONMENTAL IMPACT	REGIONAL IMPLICATIONS
Thickness of the coal seam	The amount of land disturbed	Ecological impacts	Minable coal seam thickness ranges from less than several feet in the Eastern Province to more than 50 feet in the Northern Great Plains. Ecological impacts that are caused by direct land disturbance due to surface mining include preemption of wildlife habitat, recreational areas, and agricultural lands. These will be more serious in the East than in the West.
Sulfur content of the coal	Sulfur emissions	Air quality and ecological impacts	Average sulfur content ranges from less than one percent in the Northern Great Plains and Rocky Mountain provinces to more than four percent in the Interior Province. However, the potential for increased SOx emissions in the East is partially offset by the ability to add emission controls to a synthetic fuel facility. Sulfur emissions affect ambient air concentrations of SOx and acid rain formation; acid rain, in turn, reduces species diversity and productivity in terrestrial and aquatic ecosystems. These problems are, therefore, potentially more serious in the East than in the West.
Ash content of the coal	Solid waste amounts	Ecological and water quality impacts	Ash content ranges from about seven percent in the Northern Great Plains Province to as much as fifteen percent in the Eastern Province. Thus, the amount of solid waste that requires disposal is greater in the Eastern Province than in the Northern Great Plains. The amount of land required for solid waste disposal increases with ash content as do the ecological impacts caused by that disturbance. To the extent that leaching from the solid waste disposal sites occurs, water quality is affected.
Rainfall	Reclamation potential, potential for flooding, potential for seepage. The need to discharge effluents	Ecological and water quality impacts	Rainfall ranges from over 50 inches per year in parts of the Eastern Province to less than seven inches per year in parts of the Rocky Mountain Province. High rainfall is beneficial.In the sense that reclamation is made easier and soils are generally better. It can, however, also cause problems: floods increase the likelihood of a spill from a waste disposal site; seepage and leaching from waste disposal sites increase with precipitation and evaporation rates are lower causing water effluents to accumulate if not discharged. Thus, the high rainfall in the East reduces land impacts but increases water quality impacts; the reverse is true in the West.
Wind and inversion frequency	Air dispersion potential	Air quality impacts	A combination of wind and temperature conditions generally determines the potential for dispersion of air pollutants. While it varies both seasonally and by location within a coal province, it is generally very good in the Northern Great Plains and Gulf Coast provinces; this ameliorates air quality problems there.
Terrain	The potential for plume impaction	Air quality impacts	Rough terrain occurs through the Eastern Province and in parts of the Rocky Mountain Province. Consequently, the probability of plume impaction from synfuel stacks on elevated terrain is greatly increased; such impaction greatly increases ground level concentrations of air pollutants.

(continued)

TABLE IV.2: (continued)

An EXISTING CONDITION	Determines an INTERMEDIATE EFFECT	Which partially determines an ENVIRONMENTAL IMPACT	REGIONAL IMPLICATIONS
Population density	Wilderness character	Ecological and human health impacts	The low population density of the Great Plains and Rocky Mountain coal provinces affects the ecological sensitivity of the area. Synthetic fuel development will cause an increase in population density in the West. This increase will fragment ecosystems, fragment wildlife habitat, alter the natural appearance of the West's vistas; and in general, change its open-space character. On the other hand, with lower population density, there are fewer risks of adverse human health effects from coal liquefaction pollution.
Existing agricultural lands	Changed land use	Agricultural impacts	Agriculture is sometimes in competition with energy development for land; the Interior Coal Province is characterized by prime agricultural land--some of the best in the U.S. While land reclamation following mining in that province is possible, reclamation to existing high fertility levels is questionable. Preemption of agricultural lands by coal mining is also an issue in the Northern Great Plains--not because the land is so fertile but because reclamation is in doubt and agriculture is a way of life there.
Existing ecosystems	Reductions or modifications to land and plants	Ecological impacts	Values associated with terrestrial ecosystems include uniqueness, vastness, wildlife habitats (including endangered species habitats), recreation, and productivity. The ecosystems in the West are valued very highly for their wilderness character, vastness, and high quality wildlife habitat; in the East they are valued more for their productivity.
Existing air quality		Air quality impacts	In general, air quality is worse in the Interior and Eastern provinces than in the Northern Great Plains or Rocky Mountain provinces; non-attainment with respect to one or more criteria pollutants is more of a problem in the East. The presence of poor air quality and non-attainment will make synthetic fuel development difficult. In the Rocky Mountain Province, however, the presence of many Class I PSD areas will make synthetic fuel development difficult.
Existing water quality		Water quality impacts	Streams in the Interior and Eastern provinces are, in general, more polluted with organic and inorganic chemicals than those in the Northern Great Plains and Rocky Mountain provinces; this could make synthetic fuel develoment in the East more difficult in water quality limited streams, where additional discharges may be restricted.

ecosystems. At least four factors associated with synthetic fuel development affect these resources in a major way: land use, air emissions, water effluents, and water use.

C. TERRESTRIAL ECOSYSTEMS

1. Land Use

In the synthetic fuel development cycle, land is required directly for coal mining, transportation, and liquefaction and indirectly for the urban development that accompanies the construction and operation of a mine-liquefaction complex. Depending on the location, the indirect land uses may cause more severe ecological impacts than the direct land uses. In all regions, with or without synfuels, preemption of wildlife habitat and agricultural land by energy development, as well as by urbanization, is increasing.

Coal liquefaction creates particular concern over land use from mining impacts because of the very large coal requirements. Assuming a yield of 2.5 barrels per ton of coal, a two million b/d coal synfuel industry would consume roughly 300 million tons of coal per year, an amount equal to 37 percent of coal produced nationally in 1980.

An estimate for the area of mined lands disturbed over a 30-year period for a 2 million barrel coal-liquefaction industry can be obtained by disaggregating coal supply to eight national coal supply regions (FEA 1976). This disaggregation allows for estimates of land area disturbed based on average regional coal deposit characteristics. The U.S. Department of Energy has estimated the coal production in these regions for 1985 (U.S., DOE 1979c). The proportion of coal supplied by surface mining and the relative land-use intensity of this mining for each region is shown in Table IV.3. Based on a production weighted U.S. average of 98 acres disturbed per million tons of coal produced, a two MMb/d synfuel industry utilizing 300 million tons of coal a year (with 62 percent surface mined) would disturb about 850 square miles from surface mining over a 30-year period based on projected coal mining patterns for 1985. This does not include surface disturbances from underground mining, such as coal cleaning areas, storage, or subsidence effects.

The projected patterns are based on a major use for coal as an industrial and boiler fuel, thus, it may be biased against Interior and Appalachian (Eastern) coal, which is most suitable for direct processes. A shift to using greater proportions of Appalachian and Interior coals would favor underground mining and might reduce the extent of surface disturbance. This reduction would be counterbalanced to some extent by larger areas disturbed per ton of coal supplied from surface mines in the Interior and Appalachian regions (Table IV.3).

Ecological impacts caused by such direct and indirect land use in synthetic fuel development are discussed in three categories: land use conflicts between synthetic fuel development and agriculture, impacts on wildlife habitat in general, and impacts on sensitive wildlife species more specifically.

TABLE IV.3: ANNUAL PATTERN OF LAND USE FOR COAL SURFACE MINING PROJECTED IN 1985

Supply Region	Regional Proportion of Total U.S. Surface Mining[a]	Proportion of Surface Mined Within Each Region (%)	Surface Area Disturbed (acres per million tons production)
Northern Appalachia[b]	12	47	127
Central Appalachia[b]	13	31	214
Southern Appalachia[b]	2	57	125
Interior[c] (East section)	16	48	160
Central and Gulf Coast[d]	9	98	107
Northern Great Plains	40	100	21
Rocky Mountains	1	38	102
Southwest[e]	7	98	52
U.S. Average (Production Weighted)		62	98

Source: Based on data in U.S. DOE 1979.

[a] Projected total U.S. coal production of 1,080 tpd by 1985; 671 tons are surface mined (U.S., DOE 1979). Column totals greater than 100 due to rounding.

[b] Together these represent the Eastern Coal Province.

[c] Western Kentucky and Illinois.

[d] Missouri and states south through Louisiana and Texas.

[e] New Mexico, Southern Utah and Arizona.

2. Land Use Conflicts

Conflicts between agriculture and coal development are likely to emerge in all of the major coal regions of the U.S. In the Southeast, soybean and softwood crops may be impacted (ORNL 1978, Chapter 7); farther north, much of the Illinois Basin in Illinois and Kentucky is considered prime agricultural land (U.S., DOE 1980a, p. VIII-27; Enoch 1980); and, in the West, rangeland, and some cropland will be affected (White *et al*. 1979).

For the southeastern U.S., coal reserves underlie agricultural land primarily in northeastern Arkansas and western Kentucky. Softwood production and coal conflict primarily in Oklahoma, Texas, and Arkansas. In the West, particularly in the Northern Great Plains of Montana and North Dakota, rangeland and cropland overlie strippable coal reserves. For example, in the coal regions of Mercer, Oliver, and McLean Counties, North Dakota, about 50 percent of the land is cropland and 50 percent is grassland used for grazing. Coal development will reduce some agricultural production. However, because western states and western coal regions are large, even intense coal development is not likely to preempt more than one or two percent of the land in any one coal development area.[1] Nevertheless, for the land owner whose land is being preempted, the conflict is very real.

3. Wildlife Habitat

Land use for coal development, and the urbanization that is associated with it, both eliminates and fragments wildlife habitat. In addition, in areas where population density is low, population growth increases pressures for outdoor recreation and may result in an increase in poaching and general wildlife harrassment (White et al. 1979). Thus, the ultimate effects of coal development on wildlife will depend on (1) the type and amount of habitat that is preempted, (2) the extent to which population pressures degrade wildlife quality, and (3) the success of reclamation.

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[1] White et al. 1979 (based on an analysis of scenarios involving intense coal development for electric power and synthetic fuel).

Depending on what kind of habitat is preempted, the loss of only a small part of a population's total range may have a disproportionately large ecological effect. For example, riparian (streamside) habitat is scarce in the West and therefore especially important. Loss of one percent of riparian habitat in a coal development area would produce a much greater impact than loss of the same percentage of, for example, grassland. Similarly, if development overlies migratory routes or breeding areas, impacts can be significant. These "key" habitats may be a small portion of the total wildlife range available, but they are critical to maintaining a wildlife population (White et al. 1979). Much of the West, especially the Rocky Mountain states, still retains a wilderness character and high quality wildlife habitats. In these areas, synthetic fuel development will lower wildlife diversity locally and will probably cause a decline in the herds of game species (such as deer and elk). But, as with agricultural land, the total amount of "wild" land that is preempted directly will be a small percentage of all land.

Similarly, when urban land disturbance is scattered through a vegetational type, the resulting fragmentation compounds the effects. A relatively small amount of the total plant community is eliminated but leaves no large areas without some degree of disturbance, and thus reduces the value of the remaining habitat. In addition, human activities typically disperse animals wary of human settlements. Outdoor recreational activities, particularly the use of snowmobiles and other ORV's, bring this disturbance into the back country areas that have not previously been disturbed. In the Rocky Mountain states, low rainfall and poor soils combine to make land reclamation uncertain.

In many sections of the East, the situation is different because human population pressures are already great and more habitat has been degraded. In East Texas, for example, wildlife habitat is already in poor condition over much of the Lignite Belt (Texas Energy Advisory Council 1979). Consequently, wildlife impacts occur in the context of heavy present stress. Additionally, land reclamation is expected to be successful in the East, but landowners in East Texas prefer to reclaim the land in pasture grasses rather than as native wildlife habitat (Texas Energy Advisory Council 1979). Clearly, the impact of coal mining on wildlife depends on the use for which the reclamation is designed.

4. Sensitive Wildlife Species

Sensitive wildlife species include those that are endangered (any species which is in danger of extinction throughout all or a significant portion of its range, and which has been so designated under the provisions of the Federal Endangered Species Act of 1973) and those that are threatened (species which are likely to become endangered in the immediate future due to a continued decline in population or habitat).

In the Southeast, five mammals and five birds (ORNL 1978) that are classified as threatened or endangered are known to occur in areas where coal mining and coal conversion are projected. Of the 219 counties with coal reserves, 154 contain potential habitats for the endangered or threatened mammal and bird species.

Threatened or endangered species in the areas where coal reserves occur in the West include at least two mammals and six birds (White et al. 1979). The distribution of all of these (for example, the Bald Eagle) is widespread; any direct loss of habitat as well as degradation in habitat quality will have some effect.

5. Overall Comparison of Potential for Terrestrial Impact

The overall impacts from coal liquefaction activities can be related to the degree that modifications to terrestrial environments are assimilated or "absorbed" by the ecosystem. In areas with rich soils and moderate-to-high rainfall such as the Gulf Coast, Interior, and Eastern provinces, regrowth of vegetation occurs comparatively rapidly following a disturbance such as surface mining. However, some characteristics of the Eastern Province, such as complex topography, make restoration of environmental features difficult and contribute to reclamation problems. Table IV.4 identifies some general characteristics of terrestrial ecosystems in the major coal producing regions where coal liquefaction may occur.

Based on the existing patterns of communities and stresses, the Gulf Coast terrrestrial ecosystems appear able to absorb mining impacts substantially, and regrowth of dominant plant species is quite rapid. In the Eastern sections of the Gulf Coast Lignite Province, for example, forest areas act as an additional buffer, providing capacity for significant local and regional development.

In contrast, the arid and semiarid regions of the Rocky Mountains have a slower regrowth, and animal species are less buffered

TABLE IV.4: TERRESTRIAL ECOSYSTEMS: CHARACTERISTICS AND PROBLEMS

Province	Ecosystem Types	Existing Primary Stresses	Coal Liquefaction Effects	Implications (problem importance)
Eastern	Pine forest; maple, oak, hickory forests; agricultural lands	Urban growth, mining	Increased mining; industrial growth; localized deforestation	Numerous stresses; ecosystems somewhat resilient (ecosystems can absorb some coal liquefaction development)
Interior	Oak-hickory forest; grasslands; agricultural lands; pine forests	Urban growth; mining; agriculture	Increased mining; industrial growth; localized grassland and crop removal	
Rocky Mountain	Subalpine forest; ponderosa pine forest; sagebrush grassland	Urban growth, mining; recreational activities; and local land conversion	Increased mining; industrial growth locally near required transportation corridors; local deforestation	Numerous stresses; some ecosystems relatively fragile (ecosystem can absorb relatively little development
Northern Great Plains	Grassland; cropland; riparian deciduous trees; pine forests	Agricultural development	Increased mining; industrial growth	Comparatively few stresses, ecosystems resilient (ecosystem can absorb substantial development)
Gulf Coast	Grassland; cropland; pine forests	Urban growth; agriculture; industrial development	Increased mining; industrial growth	Numerous stresses but ecosystems resilient (ecosystems can absorb substantial development)

by dense forest stands in many areas. Thus, Rocky Mountain terrestrial ecosystems are more sensitive to direct disturbances than Gulf Coast or Eastern ecosystems.

D. AIR EMISSIONS EFFECTS ON TERRESTRIAL AND AQUATIC SYSTEMS

As described previously, synthetic fuels facilities will emit criteria pollutants as well as trace elements. Of the criteria pollutants, SO_x and NO_x emissions have the potential for the most adverse ecological impacts. SO_x can damage native and agricultural plant species directly and both SO_x and NO_x are precursors to acid rain.

Because of environmental controls, synthetic fuels facilities are not expected to produce ambient air concentrations of SO_x high enough to cause acute damage to plants in any part of the country. However, chronic exposures to lower concentrations may be another matter. Even when seasonal or yearly responses of trees to pollution are slight, the results of constant exposure may result in significant changes in ecosystem behavior over long time periods. For example, Shugart and West (1977), in simulating pollutant effects in a forest, found a reduction in growth of 0 to 20 percent, depending on the tree species. Case studies, described by Woodwell (1970), indicate that pollution causes fundamental changes in ecosystem structure; changes which reduce diversity, primary production, standing crop, and the nutrient inventory. In general, pollution causes a loss of structure; that loss of structure apparently involves a shift "away from complex arrangements of specialized species toward the generalists, away from diversity in plants and animals to monotony, away from tight nutrient cycles to loose ones with depletion in terrestrial systems and overloading in aquatic systems, and away from stability toward instability." In short, complexity and stability give way to simplicity and instability. Chronic exposure to SO_x by itself or in combination with other pollutants may induce these trends over the long term.

Perhaps of greater concern over the short term is acid rain and dry acid deposition. Acid rain may be produced downwind of an emission source when the SO_x and NO_x from that source are transformed into sulfates and nitrates and react with moisture in the air. Dry acid deposition occurs when nonaqueous gases and particles such as sulfur and nitrogen oxides and chlorides settle from the atmosphere. With moisture some of these may become dilute acid solutions. Effects on aquatic ecosystems caused by acidification are suspected to include mortality to fish eggs, salamander eggs, and frog eggs with a decline in corresponding populations. In terrestrial ecosystems, acid rain has been associated with changes in soil mechanics and vegetation (both native and agricultural). During the growing season, most of the acid rain impinges directly on plant foliage where ion exchange occurs (Likens and Bormann 1974). This may alter the leaching rates of nutrients from plant foliage and erode plant cuticles providing access to pathogens and herbivores. It also alters the leaching rate of soil nutrients.

The region most affected by acid rain is the Northeast, but the most rapid increase in acid precipitation seems to be in the

Southeast (U.S., EPA 1980, p. 8). Since the Northeast is downwind of the coal regions of the Ohio Valley, synthetic fuel development there may aggravate the situation if overall sulfur emissions increase. In the Southeast, both SO_x concentrations and acid rain may pose a threat to soybean crops, softwood harvests, and native forests.

Finally, emissions of trace elements such as mercury and arsenic have the potential to cause adverse ecological effects as they accumulate in aquatic and terrestrial food chains. Again, however, data on the fate of trace elements in ecosystems are sparse. White, et al. (1979, p. 887) indicate that mercury, emitted from coal fired power plants, may be a problem in Lake Powell (Utah and Arizona) where it is taken up in aquatic food chains and poses a threat to fisheries.

E. AQUATIC ECOSYSTEMS

1. Water Effluents

In the East, effluents from synthetic fuels facilities may reach streams directly as water discharges. In all regions, they may also reach aquatic ecosystems indirectly as leachates or accidental spills from solid waste disposal systems. Accidental product spills would produce the most acute reduction in the aquatic populations of streams and rivers.

However, releases of low levels of water pollutants from liquefaction complexes in the East could contribute to the decline of endangered aquatic populations. For example, in the South, some or all of the federally designated critical habitats for three threatened fish species occur within counties where coal development is expanding; these are listed in Table IV.5. Mining or liquefaction plant effluents which reach critical streams could have serious adverse effects on the remaining populations of these animals (ORNL 1978, p. 7-43).

2. Water Use

Synthetic fuel development requires large quantities of water, primarily for cooling. This water use will increase the frequency of low flow conditions in streams and rivers, particularly in the West.

In the West, of all the habitats, aquatic habitat is by far the most limited in extent. Further reduction in this habitat will

TABLE IV.5: THREATENED OR ENDANGERED FISH SPECIES' HABITATS IN THE SOUTHEAST WHICH ARE POTENTIAL AREAS FOR CONFLICTS DUE TO COAL EXTRACTION

Name	River	County, State
Slender chub (Hybopsis cahni)	Powell, Clinch	Claiborne, Tenn.
	Powell	Lee, Va.
	Clinch	Scott, Va.
Spotfin chub (Hybopsis monacha)	Obed, Clear Creek, Daddys Creek	Cumberland, Tenn.
	Clear Creek	Fentress, Tenn.
	Emory, Obed	Morgan, Tenn.
Yellowfin madtom (Noturus flavipinnis)	Powell	Claiborne, Tenn.
	Powell	Lee, Va.
	Copper Creek	Scott, Va.
	Copper Creek	Russell, Va.

Source: ORNL, 1978, p. 7-44.

have more widespread impacts on both aquatic and terrestrial species than changes in large areas of terrestrial habitat. In addition to affecting the aquatic community directly, reduced river flow may lower floodplain water tables, thereby affecting floodplain vegetation. Riparian marshes, important to nearly all of the wildlife in the West, could be narrowed or lost. Vulnerable rivers include the San Juan, White, Upper Colorado, and Yellowstone (White et al. 1979, p. 1069).

In addition to increasing the frequency of low flow conditions in streams, water use for the development of Texas lignite could effect fresh water inflows to estuaries (Texas Energy Advisory Council, 1979, p. 290 and 319). Since the Texas Coastal Zone is a major economic resource, protection of the productivity of these estuaries is one of the State's highest priorities. The relationship between the production of coastal zone estuaries and freshwater inflows is known to be very sensitive and is being studied extensively, but it is not yet possible to project the regional effects of flow reductions due to lignite development on freshwater inflows.

3. Overall Effect on Aquatic Ecosystems

Collectively, synthetic fuel development will impact stream and riparian ecosystems in several ways:

- Consumption of between 3,500 and 5,900 AFY of water (for a 50,000 b/d plant), depending on the location and design;[1]

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[1] Although coal liquefaction facilities consume significant quantities of water, on a per-Btu basis they consume 3 to 4 times less water than power plants (see Ballard et al. 1980).

- Continuous and intermittent discharges of wastewater, which can degrade water quality and amplify stream flow variations;
- Water pollution from synfuel plants due to accidents and floods, and spills from product transport;
- Dissolved solids and sediment loading due to runoff from surface mines; and
- Acid mine drainage from surface and underground mines, especially in the East.

Degradation of floodplain productivity and wildlife habitat as well as aquatic habitat could accrue from these changes. The extent of that degradation, however, will be critically dependent on site-specific conditions. Also, these impacts and issues are highly uncertain and controversial because such changes are difficult to quantify and are usually the cumulative result of many human activities.

As summarized in Table IV.6, from a water availability prospective, the Eastern Region is more suitable than other regions for synthetic fuel development. Water is more abundant there although conflicts over appropriate use are emerging (Ballard et al. 1980). In the West the lack of precipitation causes water availability problems--most severe in the Colorado River Basin and in parts of the Northern Great Plains Region. From a water quality perspective, however, Eastern locations are already receiving a great range of industrial and municipal discharges. In these locations, water quality may be least suitable for receiving discharges from coal liquefaction plants.

TABLE IV.6: WATER RESOURCES AND AQUATIC ECOSYSTEMS: CHARACTERISTICS AND PROBLEMS

Province	Ecosystem Types	Existing Primary Stresses	Coal Liquefaction Effects	Implications (primary problems)
Eastern	Mid and low altitude lakes; primarily continuous flowing streams and rivers	Eutrophication; acidification; siltation; organic and inorganic pollution	Discharges to receiving stream; water consumption; potential groundwater pollution; spills	Sensitive to incremental organic and inorganic pollution; additional impoundments (water quality)
Interior	Low altitude lakes; primarily continuous flow streams	Eutrophication, acidification, siltation	Discharges to receiving streams; water consumption; potential groundwater pollution; spills	Sensitive to incremental organic and inorganic pollution (water quality)
Rocky Mountain	High altitude lakes; continuous and intermittent stream types	Siltation; some pollution; impoundments	Water consumption; potential ground water pollution; spills	Sensitive to stream flow reduction (water availability and habitat modification)
Northern Great Plains	Continuous and intermittent streams	Siltation; eutrophication	Water consumption; potential groundwater pollution; spills	Sensitive to additional biological oxygen demand; local stream flow reduction (water availability)
Gulf Coast	Coastal lagoons, marshes; estuaries; broad rivers and flood plains	Drainage; filling; eutrophication	Water consumption; potential groundwater pollution; spills	Sensitive to population growth and habitat modification; pollution (water quality habitat modification)

F. SUMMARY

The overall ecological sensitivity of four coal regions in the U.S. (the Northern Great Plains, the Rocky Mountains, the Illinois Basin, and Appalachia) can be generally compared on three interrelated criteria: (1) ecosystem quality (the productivity, diversity, and uniqueness of natural habitats and agricultural lands); (2) disturbance susceptibility (the potential for indirect ecological impacts resulting from human population increase); and (3) rehabilitation potential (the capacity of people to rehabilitate natural habitats and agricultural land to ecologically stable and productive conditions after alteration by synfuel development) (U.S., DOE 1980b).

In general, many areas in western regions (both the Northern Great Plains and the Rocky Mountain states) are ecologically sensitive to development, largely because of their varied and often numerous native wildlife, good aquatic habitats, and large areas of undeveloped land. Areas with especially low siting potential include those with woody areas providing critical wildlife habitat, unique riparian ecosystems, and other prime wildlife habitat such as migration corridors, breeding grounds, wintering areas for game, and nesting sites for sensitive species.

In the East, much of the Illinois Basin has a high sensitivity and low siting potential because it is prime agricultural land; rehabilitation to the existing high fertility rates, if possible, would be very expensive. The ecological sensitivity of much of Appalachia is affected by high levels of existing disturbance.

Stream water quality, terrain, vegetation, and associated animal life have already been affected by industrial and coal development. Increased synthetic fuel development could only be accommodated by measures to restore lands and protect water quality, if existing ecosystems are to be maintained at current levels of size and diversity.

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CHAPTER V

HEALTH AND SAFETY ISSUES

A. LEGISLATIVE OVERVIEW

Occupational health and safety standards for coal liquefaction will be regulated by provisions established through the Occupational Health and Safety Act of 1970. Among regulations applicable to liquefaction facilities promulgated under this Act are measures to:

(1) Establish medical research programs and criteria to assure undiminished worker health;

(2) Establish mandatory safety and health standards for plant design and operation; and

(3) Provide for inspection and enforcement programs.

For coal synthetic fuel facilities, standards have not been established. However, standards are likely to be closely related to those for petroleum refineries which include:

(1) Work force clothing and safety wear standards (goggles, hard hats, etc.);

(2) Structural protection from physical hazards (railings, heat shields, etc.); and

(3) Protection from hazardous chemicals.

These standards are largely implemented by the Occupational Health and Safety Administration often through the adoption of relevant engineering society design standards.

Also of importance is the Toxic Substances Control Act which regulates the manufacturing, processing, distribution, use, and disposal of commercial chemical substances and mixtures. The Act provides for:

(1) Premarket notification for new substances and mixtures;

(2) Toxicity testing for new substances or old substances and mixtures that pose an unreasonable risk to human health;

(3) Inventory, handling, and use controls at all stages of product life for substances determined to be toxic; and

(4) Prohibitions on manufacture may be adopted if a reasonable basis exists.

The Act provides for delays or restrictions on manufacture, including prohibition that may be implemented by injunctive relief to protect the public. A reporting and record keeping activity for manufacture of toxic substances is required.

B. OCCUPATIONAL SAFETY AND ACCIDENT RISKS

Coal synthetic fuels plants pose a range of hazards from both normal operation and upset conditions. Risks from normal operation include exposure to noise, dusts, gases, liquids, heat, and falls from elevated areas. During upset conditions contact with hot gas and liquid streams is possible and exposure to fire and explosion is possible. Table V.1 lists some of the potential exposure from coal gasification plants documented by the National Institute for Occupational Safety and Health (U.S. HEW 1980). Similar exposures would exist for any coal liquefaction process.

The relative risk of injury or illness of petroleum, coal handling, and chemical industries provides one basis of assessing

TABLE V.1: POTENTIAL OCCUPATIONAL EXPOSURES IN COAL GASIFICATION

Unit Process	Potential Exposures
Coal handling, feeding, and preparation	Coal dust, noise, gaseous toxicants, asphyxia, and fire
Gasifier/Reactor operation	Coal dust, high-pressure hot gas, high-pressure oxygen, high-pressure steam and liquids, fire, and noise
Ash removal	Heat stress, high-pressure steam, hot ash, and dust
Catalytic conversion	High-pressure hot gases and liquids, fire, catalyst, and heat stress
Gas/Liquids cooling	High-pressure hot raw gas and liquid hot tar, hot tar oil, hot gas-liquor, fire, heat stress, and noise
Gas purification	Sulfur-containing gases, methanol, naphtha, cryogenic temperature, high pressure steam, and noise
Methanol formation	Catalyst dust, fire, and noise
Sulfur removal	Hydrogen sulfide, molten sulfur, and sulfur oxides
Gas-liquor separation	Tar oil, tar, gas-liquor with high concentrations of phenols, ammonia, hydrogen cyanide, hydrogen sulfide, carbon dioxide, trace elements, and noise
Phenol and ammonia recovery	Phenols, ammonia, acid gases, ammonia recovery solvent, and fire
By-product storage	Tar, oils, phenols, ammonia, methanol, phenol recovery solvent, and fire

Source: Adpated from U.S., HEW 1980.

occupationally related illnesses and injuries in coal liquefaction plants. Table V.2 provides selected data on the incidence of injuries and illnesses that originate from plant environmental factors associated with employment. Miscellaneous petroleum and coal products industries have a higher rate of work days lost than any of the others. The second highest is bituminous coal and lignite mining. The petroleum refining industry, the closest technical approximation to the coal liquefaction industry, has among the lowest average number of work days lost among industries listed. However, coal liquefaction plants have processes and activities common to utilities, oil, and grease manufacture, as well as the miscellaneous petroleum and coal products industries.

TABLE V.2: ILLNESS AND INJURY IN COAL AND PETROLEUM RELATED INDUSTRY (1977)

Industry[a]	Incidence Rate per 100 Full Time Workers	
	Cases	Work Days Lost
Bituminous coal and lignite mining	13.2	167.0
Petroleum refining	8.1	45.4
Lubricating oils and greases	16.0	102.0
Miscellaneous petroleum and coal products	25.0	237.0
Utilities	9.0	69.0
Industrial and organic chemicals	8.0	49.0
Oil and gas extraction	13.0	143.7

Source: U.S., Dept. of Labor, Bureau of Labor Statistics, 1980.

[a] U.S. mining average: cases = 11, work days lost = 128.
U.S. manufacturing average: cases = 13.1; workdays lost = 82.3.

The occupational risks involved in exposure to hazardous materials from coal liquefaction may be higher than risks in related industries. Many of these risks relate to the generic hazardous properties of materials in the coal liquefaction fuel cycle as listed in Table V.3. In combination these materials pose a special hazard; for example the liquefaction plants must handle large flow rates of pressurized oxygen, hydrogen, and hydrocarbons simultaneously.

TABLE V.3: EXAMPLES OF HAZARDOUS MATERIALS IN COAL LIQUEFACTION PROCESSES

Material	Hazardous Property
Coal dust	Explosive, flammable, toxic
Slag	Pyrophoric, possibly carcinogenic
Hydrogen	Flammable, explosive, asphyxiant
Methane	Flammable, explosive, asphyxiant
Carbon monoxide	Flammable, toxic
Carbon dioxide	Asphyxiant
Carbonyl sulfide	Flammable, toxic
Oxygen	Reactive, increased fire hazard
Nitrogen	Asphyxiant
Argon	Asphyxiant
Hydrogen sulfide	Flammable, toxic
Light oil (naphtha)	Flammable, toxic, explosive, carcinogenic
Medium oil	Flammable, toxic, explosive, carcinogenic
Heavy oil	Flammable, toxic, carcinogenic
Bottoms	Toxic, flammable, carcinogenic
Ammonia	Flammable, toxic
Sulfur	Flammable, toxic combustion products
Sulfur dioxide	Flammable, toxic
Hydrogen chloride	Toxic
Acid gas solvent	Flammable, toxic
Phenolics	Toxic
Hydrogen cyanide	Toxic
Liquified petroleum gas	Flammable, explosive

Source: Modified from U.S., DOE 1981.

In short, the occupational risks arise from:

(1) High pressure vessels and process streams;

(2) High temperatures;

(3) Presence of erosive materials that can lead to failure of walls and piping; and

(4) Toxicity of process compounds.

Many factors affect the safety of a coal liquefaction plant including redundant design, plant layout, maintenance programs, and industrial hygiene. However, since final design, operational experience, and company performance safety data are not available, the actual occupational risks cannot be determined.

Table V.4 presents comparisons of direct and indirect processes, indicating the processes differ substantively in the kinds of risks. Direct liquefaction processes basically are more complex. They require gasification sections for hydrogen generation. These sections use high-pressure oxygen (produced at very low temperatures) and yield hydrogen and carbon monoxide at high temperatures which is basically the same as the gasification step in the indirect route. Direct processes also require more complex reactor feed operations and must handle ash entrained with reactor products under moderate temperature (850° to 900°F) and high pressure (1,500 to 3,000 pounds per square inch [psi]). Selected characteristics of these reactors are listed in Table V.5. Downstream from the reactor, direct processes also must handle gas, liquid, and solid phase separation, where indirect processes have only a two-phase separation (gas and liquid). Additional hydrogenation is also required with direct process product intermediates. These steps

TABLE V.4: COMPARISON OF SELECTED ACCIDENT HAZARDS BETWEEN DIRECT AND INDIRECT PROCESSES

Process Steps	Indirect Processes	Direct Processes	Relative Safety Advantage
Coal handling and preparation	Requires more handling per Btu of liquids produced[a]	Requires less handling per Btu of liquids produced	Direct
Slurry preparation/preheating	None or limited slurry system	Moderate temperature (650° - 750°F)	Indirect
Reactors/gasifiers			
Pressures	Low to moderate (1,200 psia)	High presures (2,000 - 3,000 psia)	None
Temperatures	High Temperature (1,100° - 3,000°F)	Moderate temperatures (900°F)	Direct
Oxygen plant	Moderate presure, cryogenic temperatures	Moderate pressure, cryogenic temperatures	None
Hydrogen plant	Not a separate unit	Low to high (1,200 psi) pressures, high temperature (1,100° - 3,000°F)	Indirect
Distillation units	Low to moderate temperature	Low to moderate temperature, More and larger units	Indirect
Additional hydrogenation	Separate hydrogenation not required for Methanol and MTG	Required to make lighter fuel cuts and to reduce sulfur and nitrogen levels	Indirect

psia = pounds per square inch atmospheric

[a] See Chapter II, Section D.

TABLE V.5: SELECTED GASIFIER/REACTOR CHARACTERISTICS

Type	Feed (inputs)	Outputs	Pressure (psia)	Temperature (approx. °F)
Indirect Processes				
Koppers-Totzek	Coal, steam, oxygen	Gas, ash	15	3,000
Lurgi	Coal, steam, oxygen	Gas, ash	300-500	1,100
Shell-Koppers	Coal, steam, oxygen	Gas, ash	150	1,500
Winkler	Coal, steam, oxygen	Gas, ash	15	1,500
Texaco	Coal, steam, oxygen	Gas, ash	1,000-1,500	2,300
Direct Processes[a]				
EDS	Coal slurry, hydrogen,	Process stream	2,000	850-900
H-Coal	Coal slurry, hydrogen, catalyst	Process stream catalyst	3,000	850-900
SRC-II	Coal slurry, hydrogen, recycle bottoms	Process stream	2,000	850-900

[a] Direct processes also generally have an indirect process gasifier for hydrogen generation. However, hydrogen can also be generated by steam reforming of methane produced in the reactor (although methane is a valuable by-product that may be marketed).

require additional product flow for a given unit of product output. Potential accident sources associated with steps in direct coal liquefaction are indicated in Appendix C. On the basis of mechanical design features, direct process might be expected to result in higher rates of upsets than indirect process. However, this is based on complexity and process flow requirement alone as contributors to overall plant hazards. Clearly a complex but carefully designed and operated plant can be safer than a simple but poorly designed and carelessly operated plant.

In addition to these differences, direct processes also must mechanically handle liquids containing entrained solids (ash, catalyst, or both). Indirect processes only handle ash in the gasifier step while direct processes typically handle the ash through steps that include hydrogen separation, water removal and phenol separation, and distillation. This entrained ash can erode valves and piping (especially joints and elbows). Designs to minimize this erosion are an important part of the engineering steps from bench scale through commercial operation and are one of the major reasons for needing demonstration and pioneer plants. This is essentially because the science of scaling solids handling is not well developed, and still a trial and error activity compared to the relatively predictable nature of fluids.

Another significant difference among direct and indirect facilities is the type of compounds found in process streams and in products. Because direct liquefaction breaks down large aromatic molecules, it results in more complex molecules in the product than do the indirect processes (see Chapter II). The direct process molecules contain more sulfur, nitrogen, and more of the reactive aromatic compounds that pose a greater health risk, including polynuclear aromatics with carcinogenic and mutagenic activity, as described in the following sections.

C. OCCUPATIONAL AND PUBLIC HEALTH RISKS

As indicated in Chapter II, the process stream composition and product mix from alternative liquefaction technologies vary. Because occupational health risk is related to the exposure to chemicals, it is appropriate to assess the composition of process streams and products.

1. Process Stream Composition

Table V.6 summarizes process stream composition for three direct and three indirect coal liquefaction processes. This summary comparison indicates that indirect liquefaction process with Lurgi gasifiers produce a wider range of organic compounds than higher temperature gasifiers, including heavy oil and tars that contain polynuclear aromatic hydrocarbons and polynuclear aromatic amines. Entrained and fluid bed gasifiers that operate at high temperature, such as Texaco, Koppers-Totzek, and Winkler produce gas consisting primarily of hydrogen, carbon monoxide, water, and methane. Purified hydrogen/carbon monoxide mixtures can be catalytically converted to methanol, gasoline, or Fischer-Tropsch liquids. These compounds have not been directly related to chronic disorders such

TABLE V.6: PREDOMINANT PROCESS STREAM AND PRODUCT COMPONENTS

Process	Reactor/Gasifier Output	Intermediate Streams	Products
Indirect processes with entrained or fluidized bed gasifier			
Methanol	Hydrogen Carbon monoxide Methane	Methane	Methanol
Coal to methanol to gasoline	As above	Methanol	Gasoline
Fischer-Tropsch	As above	Naphtha Light, middle, and heavy oils	Naphtha Light, middle, and heavy oils
Indirect processes with Lurgi gasifier	As above, plus naphthas, oils, and tars	As above, plus tars	As above, plus tars
Direct processes			
EDS	Naphtha, light, middle, and heavy oils	Same	Same, with shift to lighter fractions
H-Coal			
SRC-II			

as cancer, although of course, they can produce adverse effects if ingested or inhaled.

Compared to indirect approaches, direct processes produce greater amounts of polynuclear aromatic amines and polynuclear aromatic hydrocarbons. These chemical groups are present in reactor products and are introduced into process wastewaters. They are also present in the higher boiling point distillate fractions and in the distillate bottoms (ash), or in the SRC II process, in the vacuum bottoms. The fate of these bottoms fractions has been discussed in the section on solid waste. The relative health hazard of these specific process fractions has been subject to continuing laboratory studies.

2. Product Composition

Coals typically contain a mixture of more than 500 compounds, most of which are large complex molecules. Decomposition and hydrogenation of these large molecules in direct process create liquids with both straight chain and ring compounds. The heavier, more viscous liquids contain significant fractions of polynuclear aromatic compounds and polynuclear amines as discussed above.

Composition of products from the SASOL Lurgi/Fischer-Tropsch liquefaction plant in South Africa are provided in Table V.7. This analysis indicates aromatic hydrocarbons are produced primarily from the fluid bed process section of the plant.

As indicated in Table V.8, liquid products from the H-Coal process include paraffins, olefins, monocyclic and polycyclic aromatic compounds, and phenolic compounds (Hydrocarbon Research, Inc.,

TABLE V.7: TYPCIAL PRODUCTS--FISCHER-TROPSCH PROCESS

Component	Composition (volume %)	
	Fixed-Bed Process	Fluid-Bed Process
Liquifed petroleum gas $(C_3 - C_4)$[a]	5.6	7.7
Petrol $(C_5 - C_{11})$[a]	33.4	72.3
Middle Oils (diesel, furnace, etc.)	16.6	3.4
Waxy oil or gatsch	10.3	3.0
Medium wax, mp 203-206°F	11.8	
Hard wax, mp 203-206°F	18.0	
Alcohols and ketones	4.3	12.6
Organic acids	Traces	1.0
Total	100.0	100.0

Liquid Products Fraction[b]	$C_5 - C_{10}$	$C_{11} - C_{18}$[a]	$C_4 - C_{10}$	$C_{11} - C_{14}$[a]
Paraffins	45	55	13	15
Olefins	50	40	70	60
Aromatics	0	0	5	15
Alcohols	5	5	6	5
Carbonyls	Traces	Traces	6	5
Total	100	100	100	100

Source: Bodle and Vyas 1974, p. 78, as cited in Braunstein, Copenhaver and Pfuderer 1977.

[a] Subscript indicates the numbers of carbon atoms in the molecule.

[b] Refers to composition of petrol and middle oils listed above.

TABLE V.8: H-COAL LIQUID PRODUCT COMPOSITION (weight percent in each boiling range)[a]

Boiling Range and Chemical Group	Illinois No. 6 Coal	Wyoming Subbituminous
400°F and lower boiling liquids		
Saturated compounds	12.0	14.7
Olefins, diolefins	--	4.2
Alkyl benzenes	17.5	14.6
Saturated napththenes	51.3	42.9
Unsaturated naphthenes	11.2	16.7
Other compounds	7.9	7.6
Total	100.0	100.0
400° - 650°F		
Saturated compounds	31.0	22.7
Unsaturated nonaromatic	4.3	4.5
Aromatic compounds	59.6	65.8
Other compounds	5.1	7.5
Total	100.0	100.0
650° - 919°F		
Saturated compounds (paraffins and cycloparaffins)	6.8	11.0
Unsaturated nonaromatic	1.6	1.5
Other compounds	91.6[b]	87.5[c]
Total	100.0	100.0

Source: Braustein, Copenhaver, and Pfuderer 1977.

[a] Values rounded and may not total 100 percent for each boiling range.

[b] 79.8 percent of this group are aromatic-type compounds.

[c] 74 percent of the fraction are aromatice-type compounds.

1968). Overall, aromatic compounds constitute the largest percentage of the mid- and high-boiling point range products of this direct liquefaction technology (Braunstein, Copenhaver and Pfuderer 1977). As discussed in the following section, these and related compounds post the greatest health risk.

3. Potential Health Effects

The health risk of coal-derived liquids and related compounds and mixtures has long been recognized. For example, occupational cancers related to coal products have an old history--it was first recognized by Paft, an eighteenth century English surgeon, who related a high incidence of cancer among chimney sweeps to their exposure to soot (Paft 1775).

The principle questions about health risks from the synthetic fuels industry are:

(1) What fractions pose the greatest health risks?

(2) What is the type and degree of risk?

(3) What differences occur among technologies? and

(4) What are the possible mitigating measures?

Research to address these questions involves systematic laboratory testing of chemicals in process streams, plant emissions and effluents, and end-products. Tests can be utilized to evaluate direct toxicity, genetic changes, carcinogenicity, or other effects (see Table V.9). Because continued exposure to low levels of some materials can produce significant increases in the risk of cancer, this group of diseases has been the focus of synfuels health concerns.

TABLE V.9: TYPES OF BIOLOGICAL TESTS AND EFFECTS

Problem or Impact	Test
Cell toxicity (cytotoxicity)	Bacteria and protozoa exposure
Genetic change (mutagenesis)	Salmonella (bacteria) Yeast Fruit flies Human blood cells Mammal cells
Cancer effect (carcinogenesis)	Organ cultures Skin painting Inhalation tests Ingestion tests Injection tests
Birth abnormalities (teratogenesis)	Mammal tests
Organism effect	Short-term test
Physiological organ system toxicity	Long-term exposure

Although a "battery" or group of tests is the best line of laboratory evidence to indicate the health risk of synfuel process intermediates, effluents, and products, typically only a few tests can be performed. Tests on the ability of a chemical to produce genetic change or damage, "mutagenicity" can be performed using bacteria (the so-called Ames test). Because mutagenesis is one contributor to carcinogenesis and to birth defects (teratogenesis) the Ames test has been a powerful chemical screening tool.[1]

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[1] The Ames test using bacteria can be used to test for several changes to bacterial genes. However, some chemicals may not damage bacterial genes, but damage human genes. These "false negative" Ames results are a shortcoming to using the Ames test alone.

The mutagenicities of coal-derived oils are due to both basic (alkaline) and neutral constituents of the oils. Mutagenic alkaline compounds in oils derived from shale or coal are aromatic primary amines. While these constituents may represent a biological hazard unique (as compared to petroleum) to synfuels, they would be expected to be reduced significantly and perhaps eliminated by hydrotreating. Initial evaluation of the influence of hydrotreating on the contribution of alkaline mutagnes to total mutagenicity confirms this finding (Richmond 1979).

However, neutral constituents are also major contributors to the mutagenicities of shale, coal, and petroleum crude oils. Chemical and biological studies suggest that polycyclic aromatic hydrocarbon compounds are the responsible agents. Mutagenicity is greatest in the larger four- to five-ring compounds which are the heavier, higher boiling point fractions (Richmond 1979). A listing of major groups of potential mutagens and carcinogens in coal derived compounds is given in Table V.10.

> In general, for the number of materials examined, coal-derived synfuel products appear to be more mutagenic than shale-derived products which in turn are only slightly more mutagenic than petroleum crude oils. This increased mutagenicity is due to both the greater quantity of polycyclic aromatic hydrocarbon compounds present and to the presence of polycyclic aromatic primary amines in the synfuels. Experience to date suggests that the mutagenicity observed is caused by less than 10 percent and perhaps as little as one percent of the mass of the oils (Richmond 1979, p. 30).

Continuing studies of the toxicity of the SRC II process intermediates and products provides examples of the mutagenicity and carcinogenicity of coal-derived products. Table V.11 indicates,

TABLE V.10: CLASSES OF POTENTIAL MUTAGENS/CARCINOGENS IDENTIFIED IN SYNFUELS

Basic	Neutral (PNA)
Quinoline	Benzanthracenes
Substituted quinolines	Dibenzanthracenes
Alkyl pyridines	Substituted anthracenes
Acridines	Benzopyrenes
Naphthylamines	Benzofluorenes
Aza-arenes	Pyrenes
Benzacridines	Substituted pyrenes
Aromatic amines	Chrysenes

Source: Richmond 1979.

TABLE V.11: COMPARISON OF MUTAGENICITY FOR SOLVENT REFINED COAL MATERIALS

Material	Reverents/µg[a]
SRC II	
Heavy distillate	40.00 ± 23.00
Middle distillate	0.01
Light distillate	<0.01
SRC I	
Process solvent	12.00 ± 2.00
Wash solvent	<0.01
Light oil	<0.01
Shale Oil (Parahoe)	0.60 ± 0.2
Crude Petroleum (Prudhoe Bay)	<0.01
Benzo (a)pyrene	114.00 ± 5.0
2-Aminoanthracene	5,430.00 ± 394.0

Source: Pacific Northwest Laboratories 1979.

[a] Revertants are observed chemical changes to bacterial cultures that have been directly related to a genetic alteration (mutation).

for example, that the heavy distillate fractions contain most, if not all, of the mutagenic effects. Table V.12 indicates that skin tumors on mice are produced also by heavy distillate fractions. This fraction may represent a small proportion of the total SRC II product, and tests are now being conducted to determine what boiling point cut is responsible (Pacific Northwest Laboratories 1980). If cuts in the range of 700°F to 750°F are responsible, for example, only a small part of product stream (e.g., about 5 percent) may be carcinogenic, and this fraction might be used for boiler fuels at the plant site.

In summary, studies of SRC II product fractions and fractions from other processes indicate common findings on mutagenicity and carcinogenicity:

TABLE V.12: SKIN TUMOR INCIDENCE IN MICE[a]

	Tumor Incidence	Minimum Latency (days)
SRC II		
Heavy distillate	47/47	72
Light distillate	1/44	427
Shale oil	41/50	148
Crude petroleum (Wilmington)	3/45	282
Benzo (a)pyrene[b]	50/50	106
2-Aminoanthracene[b]	25/32	115

Source: Pacific Northwest Laboratories 1979.

[a] 456 days of exposure to 2 milligram applications except as noted.

[b] .05 milligram application.

(1) That the heavy distillate fraction (above 650°F) contains all or nearly all of the mutagenic and carcinogenic activity;

(2) That three-, four-, or five-ring polynuclear aromatic amines and polynuclear aromatic hydrocarbons are responsible for this biological activity;

(3) That acute toxicity to cells, i.e., cytoxity, is greater in lighter fractions (Pacific Northwest Laboratories 1979), but these fractions are not generally active against skin of mammals;

(4) Light, mid, and heavy distillate fractions are moderately toxic upon ingestion (oral administration). Continuous maternal ingestion of all distillate fractions also apparently has adverse effects on fetal growth. It is widely recognized, however, that direct ingestion of most hydrocarbons produces adverse physiological effects.

Developers of liquefaction processes are aware of the potential health hazards of synthetic liquid fuels and are taking particular care of the hygiene of workers. Cleaned, fresh clothing is provided daily with periodic medical check-ups, a practice developed to reduce cancer among wax-press (removing wax from lubricating oil) workers (Eckardt 1967). Concern for hygiene may be most important since the PNA's concentration in the air would be very low.[1] Medical supervision will also be essential for workers--particularly those in areas where heavy liquids are processed.

The longest exposure period for U.S. workers in coal liquefaction plants (pilot scale) from whom health effects have been reported is approximately 11 years. In this case no internal organ cancers were reported, but carcinomas reportedly occurred on exposed parts of the body (lip, ear, and nose) in 3 of 190 employees. However, the significance of these cases is uncertain because of the small number of employees involved and the lack of background data. These data are currently being acquired by personnel at pilot coal liquefaction plants (Harris, *et al*. 1980).

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[1] Laboratory tests on inhalation of coal-tar pitch (probably closely related chemically to coal-derived heavy liquids) fumes inhaled by laboratory animals failed to produce cancers or tumors in lungs or other organs of experimental animals (Puzinaukas and Corbett 1978, p. 15).

Foreign plants have operated for a number of years (from 1927 to 1945 in Germany, and from 1955 to the present in South Africa), but no epidemiologic studies have been undertaken. The SASOL indirect liquefaction plant is presently the largest commercial process in operation; it has been operating for over 23 years and currently employs approximately 5,600 workers. The National Institute of Occupational Safety and Health (NIOSH) personnel have visitied the Lurgi gasification and tar handling sections of the plant and have discussed health problems with the plant physician and workers (Harris, *et al*. 1980). NIOSH personnel reported that skin cancer was not observed among the gasifier and gas clean-up crew, nor among the workers of the coal tar separators. However, plant record keeping did not include chronic disease such as cancer, and follow-up studies on workers have not been undertaken (Harris, *et al*. 1980).

U.S. epidemiologic study on skin cancer incidence at a coal liquefaction plant in West Virginia that operated for 7 years (Harris *et al*. 1980) was based on 359 workers, of whom 50 had skin abnormalities. Of these 50 workers, 10 were diagnosed as having skin cancer. NIOSH subsequently reviewed the data from this study and followed up 49 of these workers (Palmer 1979). Only 5 of the 10 were confirmed as having had skin cancer. These findings did not support the initial hypothesis (Sexton 1960) that workers exposed to toxic materials from the coal liquefaction process, particularly those with evidence of skin abnormalities, were at increased risk of developing systemic cancer, compared with the general population (Harris, et al. 1980).

The significance of these studies relative to current direct liquefaction processes is uncertain because the technology used in the West Virginia plant was different from current process technology (operating pressures were 5- to 10-fold greater than the current processes), and the hygiene, sanitation, work practices, and controls were not implemented as rigorously as in current pilot plants (Harris, et al. 1980). This greater emphasis on occupational health may account for an apparent absence of occupational disease in the newer pilot plants over an equivalent operating period. However, numerous cases of thermal burns and dermatitis have been reported for these plants (Harris, et al. 1980).

If potential carcinogens are present only in the higher boiling liquids in these coal liquefaction plants, a way to prevent exposure to a broader spectrum of workers and the general public would be to utilize all those heavy materials within the plant confines--by reducing them through hydrocracking or consuming them to produce hydrogen or electric power. Whether or not such an approach be reasonable would depend upon analysis of the effect on overall plant efficiency. Another alternative would be to have dedicated customers for the heavy liquids where hygiene and medical supervision would be possible. It would seem inadvisable to make these heavy fractions general articles of commerce until much more information is available on their health hazards. In short, four options could be evaluated for minimizing health risks of products:

(1) Optimize process operations to minimize the production of toxic materials;

(2) Utiize all carcinogenic fractions on site;

(3) Develop special protocols for marketing and handling identified toxic product; and

(4) Refine and upgrade product by hydrotreating and hydrocracking to reduce toxicity.

In addition to the chemicals identified above whose carcinogenicity and mutagenicity has been well documented, other chemicals present in process or waste streams pose potential but uncertain risks. This risk is uncertain either because concentrations are small and exposures are low, or the health consequences are poorly understood. Categories of health effects concerns for these coal liquefaction chemicals are listed in Table V.13. Sources of chemicals in the category are:

(1) Light distillates: (e.g., benzene, indole);

(2) Middle distillates: (e.g., quinolene, aniline, thiophene);

(3) Middle and heavy distillates: (e.g., creosols);

(4) Gaseous materials: (e.g., hydrogen sulfide and carbon disulfide); and

(5) Ash: (e.g., arsenic, mercury, nickle, chromium, lead, and cadmium).

These chemicals may also occur in other process fractions. For

TABLE V.13: SUMMARY EFFECTS OF SELECTED ORGANIC COMPOUNDS AND TRACE ELEMENTS

Chemical	Carcinogenic	Chromosome Damage	Teratogenic	Other Reproductive and Developmental Toxicity	Neurotoxic	Toxic to Other Organ Systems
Benzene	x					
Aniline	x					Circulation
Indole	x					
Phenols		x				
Cresols		x			x	Circulation
Thiophene						
Hydrogen sulfide			x		x	Excretion
Carbon disulfide			x	x	x	
Arsenic	x					
Mercury			x		x	Excretion
Nickel	x					Skin
Chromium	x					Skin
Lead	x			x	x	Circulation
Cadmium	x	x	x	x		Excretion

Source: Adapted from Dean and Lash 1980.

example, mercury is vaporized in boilers, and would be emitted in small concentrations in stack gases, in addition to being present in ash, other waste streams, and to some small, but poorly known level, in products. Because trace organic compound and trace element materials balances have not been completed for coal liquefaction processes, the location and concentration of these materials is poorly known, and health risks are therefore highly uncertain.

D. SUMMARY

The significant health and safety risks that exist in coal liquefaction facilities are primarily related to potential accidents and to exposure to carcinogenic hydrocarbon compounds. Among the more critical problems are:

- Potential accidents in the plant are related to high temperature and pressures, combined with explosive materials and oxygen. The coal product industry has among the highest accident rates among U.S. industrial sectors.
- Direct processes may be more hazardous due to accidents than indirect process because of the complexity of plants and entrained solids in process streams. However, data is generally inadequate to make a definitive evaluation of differences among processes.
- The occurrence of polynuclear aromatic hydrocarbons and aromatic amines in process streams from Lurgi indirect processes and direct processes necessitates special handling of some process fractions, and special industrial hygiene practices. Because worker exposure can not be completely controlled, and the hygiene practices have not been developed for commercial operations, the actual extent of health risks reductions are uncertain.
- There will be a large variety of organic and inorganic chemicals and trace elements in process streams, waste streams, and end-products that will pose health risks (e.g., aniline, carbon disulfide, and mercury). However, the degree of health risks associated with coal liquefaction are largely unknown and will always be difficult to assess because of low concentrations and expected low exposure levels.

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APPENDIX A

RESIDUALS DATA FOR COAL LIQUEFACTION PROCESSES

TABLE A-1: AIR EMISSIONS FROM COAL LIQUEFACTION PROCESSES: NORMALIZED EMISSIONS IN tpd FOR A 50,000 b/d FACILITY

Process	Reference*	Unit and Basis of Numbers in Reference	Particulates		SO_2		NO_x	
			From Source	Normal-ized	From Source	Normal-ized	From Source	Normal-ized
INDIRECT								
Coal-Methanol-Gasoline								
Case 1	[1,2]	g/s for 45,000 b/d plant	8.8	0.93[a]	84	8.9[a]	147	15.5[a]
Case 2	[3]	tpd for 50,000 b/d plant; 0.45% S coal		0.5-1.5		9-14		5-8
Case 3	[7]	tpd for 100,000 b/d plant	15	7.5	26	12	NC	
Case 4	[9]	tpd for 100,000 b/d plant	7	3.5	12	6	NC	
Fischer-Tropsch								
Case 1	[1,2]	g/s for 45,000 b/d plant	56.5	6.0[a]	115	12.2[a]	223	23.6[a]
Case 2	[3]	tpd for 50,000 b/d plant; 0.45% coal		1-1.5		9-14		5-8
DIRECT								
EDS								
Case 1	[1,2]	g/s for 60,000 b/d plant without on-site power generation	4.8-	0.38-	214.2-	17.0-	66.6-	5.3-
Case 2	[1,2]	g/s for 60,000 b/d plant with on-site power generation	9.5	0.75[b]	344.2	27.3[b]	158.6	12.6[b]
Case 3	[3]	tpd for 50,000 b/d plant; 0.4% S coal		0.3-0.4		16-18		5-6
Case 4	[4]	lbs/hr for 60,000 b/d plant;[c] Illinois #6 coal	44	0.44[d]	1,714	17.14[d]	532	5.32[d]
H-Coal								
Case 1	[5]	lbs/hr for 60,000 b/d plant; Illinois #6 coal	9.2	0.09[d]	NC		NC	
Case 2	[7]	tpd for 100,000 b/d plant	2.7	1.3	16	8	NC	
Case 3	[8]	tpd for 100,000 b/d plant	0.4	0.2	21	10.5	NC	
Case 4	[9]	tpd for 100,000 b/d plant	7.0	3.5	11	5.5	NC	
SRC II								
Case 1	[3]	tpd for 50,000 b/d plant; 3.5% S coal		2-3		5-10		9-10
Case 2	[6]	tpd for 6,000 tpd plant	1.7	6.8	3.4	13.6	5.65	22.6

continued

TABLE A.1: (continued)

Process	Reference*	Unit and Basis of Numbers In Reference	CO From Source	CO Normal-Ized	HC From Source	HC Normal-Ized	CO_2 From Source	CO_2 Normal-Ized
INDIRECT								
Coal-Methanol-Gasoline								
Case 1	[1,2]	g/s for 45,000 b/d plant	NC		NC		NC	
Case 2	[3]	tpd for 50,000 b/d plant; 0.45% S coal	NC		NC		NC	21,000
Case 3	[7]	tpd for 100,000 b/d plant	NC		NC		NC	
Case 4	[9]	tpd for 100,000 b/d plant	NC		NC		NC	
Fischer-Tropsch								
Case 1	[1,2]	g/s for 45,000 b/d plant	NC		NC		NC	
Case 2	[3]	tpd for 50,000 b/d plant; 0.45% coal	NC		NC			21,000
DIRECT								
EDS								
Case 1	[1,2]	g/s for 60,000 b/d plant without on-site power generation	NC		NC		NC	
Case 2	[1,2]	g/s for 60,000 b/d plant with on-site power generation	NC		NC		NC	
Case 3	[3]	tpd for 50,000 b/d plant; 0.4% S coal		1-1.5		0.01-1.0		14,000
Case 4	[4]	lbs/hr for 60,000 b/d plant;[c] Illinois #6 coal	124	1.24[d]	2	0.02[d]	NC	
H-Coal								
Case 1	[5]	lbs/hr for 60,000 b/d plant; Illinois #6 coal	NC		NC		1.12410^6	11,200[d]
Case 2	[7]	tpd for 100,000 b/d plant	NC		NC		NC	
Case 3	[8]	tpd for 100,000 b/d plant	NC		NC		NC	
Case 4	[9]	tpd for 100,000 b/d plant	NC		NC		NC	
SRC II								
Case 1	[3]	tpd for 50,000 b/d plant; 3.5% S coal		1.5-2.5		1-2		14,000
Case 2	[6]	tpd for 6,000 tpd plant	0.4	1.5	0.56	2.2		

*See page A-3 for references and footnotes.

continued

Sources for Table A-1:

[1] U.S., DOE 1980a, Appendix H.

[2] U.S., DOE 1980b, Appendix K.

[3] U.S., DOE 1980b, p. 3-23.

[4] U.S., EPA 1979a, pp. 77 and 83.

[5] U.S., EPA 1979a, pp. 44, 47, 50, 53.

[6] U.S., DOE 1980c.

[7] U.S., DOE 1980a, p. B-4, originally MITRE Corporation, "Environmental Data for Energy Technology Policy Analysis" Vol. 1, prepared for DOE/EV/OTI, Contract No. EE-77-C-01-6118, 1979.

[8] U.S., DOE 1980a, p. B-4, originally MITRE Corporation, "Preliminary Final Environmental Impact Statement Coal Research and Demonstration Program" (Working Paper), Vol. II, prepared for DOE, Contract No. EF-77-C-01-2783, 1978.

[9] U.S., DOE 1980a, p. B-4, originally SRI, "Synthetic Fuel Development: Assessment of Critical Factors" Vol. II, prepared for ERDA and EIA, Contract No. E(04-3)-1115, 1976.

Footnotes to Table A-1

[a] To convert grams per second to tpd and scale to 50,000 b/d, multiply by 0.10584:

$$\frac{50{,}000\ \text{b/d}}{45{,}000\ \text{b/d}} \times 2.205 \times 10^{-3}\ \frac{\text{lb}}{\text{g}} \times \frac{1}{2{,}000}\ \frac{\text{tons}}{\text{lb}} \times 86.4 \times 10^{3}\ \frac{\text{sec}}{\text{day}}$$

[b] To convert grams per second to tpd and scale to 50,000 b/d, multiply by 0.07938:

$$\frac{50{,}000\ \text{b/d}}{60{,}000\ \text{b/d}} \times 2.205 \times 10^{-3}\ \frac{\text{lb}}{\text{g}} \times \frac{1}{2{,}000}\ \frac{\text{tons}}{\text{lb}} \times 86.4 \times 10^{3}\ \frac{\text{sec}}{\text{day}}$$

[c] Reference 4 did not give plant size; calculated assuming 60,000 b/d for the 1,000 ton per hour (24,000 tpd) facility using 12,600 Btu/lb Illinois coal.

[d] To convert lbs/hr to tpd and scale to 50,000 b/d, multiply by 0.01:

$$\frac{50{,}000\ \text{b/d}}{60{,}000\ \text{b/d}} \times \frac{1}{2{,}000}\ \frac{\text{tons}}{\text{lb}} \times \frac{24\ \text{hrs}}{\text{day}}$$

[e] Reference 5 did not give plant size; calculated assuming 60,000 b/d for the 24,000 tpd facility using 12,600 Btu/lb Illinois coal.

[f] Reference 6 did not give plant size; calculated assuming 60,000 b/d from data on page 45 of reference 6.

[g] To convert grams per day to tpd and scale to 50,000 b/d, multiply by 9.186 x 10^{-7}:

$$\frac{1}{453.6}\ \frac{\text{lb}}{\text{g}} \times \frac{1}{2{,}000}\ \frac{\text{tons}}{\text{lb}} \times \frac{50{,}000\ \text{b/d}}{60{,}000\ \text{b/d}}$$

TABLE A-2: SOLID WASTES FROM COAL LIQUEFACTION PROCESSES: NORMALIZED TO A 50,000 b/d FACILITY

Reference	Basis of Numberes in Reference	Indirect				Direct					
		Coal-Methanol-Gasoline		Fischer-Tropsch		Exxon Donor Solvent		H-Coal		SRC II	
		Reference	Normalized	Reference	Normalized	Reference	Normalized	Reference	Normalized	Reference	Normalized
Reference 1											
Waste Group 1	45,550 b/d for CMG	1681	1845	1774	1973	2225	1854	NC		NC	
Waste Group 2	44,950 b/d for F-T	NC		67	75	2750	2292				
Coal Prep. Refuse	60,000 b/d for EDS	NC		NC		NC					
Reference 2	50,000 b/d										
Waste Group 1			1800-2000		1800-2000		2500-3000		NC		5000-7000
Waste Group 2			NC		NC		NC				NC
Coal Prep. Refuse			~0		~0		8000-9000				8000-9000
Reference 3	60,000 b/d	NC		NC						NC	
Waste Group 1						2780[d]		2640[a]	2200		
Waste Group 2						NC[c]		984[b]	820		
Coal Prep. Refuse						NC		NC			
Reference 4	60,000 b/d	NC		NC		NC		NC			
Waste Group 1										4706[e]	3922
Waste Group 2										>54[f]	>45
Coal Prep. Refuse										8502[g]	7085

*Waste group 1 includes the waste generated directly by the process that is part of the original coal feed such as ash and unexpected carbon; waste group 2 includes secondary added materials and chemicals such as catalysts, coal conditioners, lime from scrubbers and added reactants from water treatment.

References for Table A-2

[1] U.S., DOE 1980b, Appendices C, D, E and F.

[2] U.S., DOE 1980a, p. 3-23.

[3] U.S., EPA 1979a, pp. 44-55 and 77-82.

[4] U.S., EPA 1979b, pp. 252-57.

Footnotes to Table A-2

[a] Reference 3, p. 44 gives 110 tons per hour or 2640 tons per day assuming that a large portion of these vacuum tower bottoms are recycled and burned to produce hydrogen. If no recycle occurs, the value would be 322 tons per hour or 7728 tons per day.

[b] Reference 3, p. 47-52 gives 40 tons per hour or 960 tons per day of sludge from the wastewater treatment system and 1.0 tons/hour or 24 tons/day of spent catalyst.

[c] Amounts were not given in reference 3, but oily sludges, digested biological sludge, and spent catalyst are produced (reference 3, p. 82)

[d] Represents ash residue from the flexicoker.

[e] Reference 4 gives 66 x 10^6, 36 x 10^6, 92 x 10^6 and 4075 x 10^6 grams per day for bottom ash, fly ash, gasifier slag, and hydrogen production residue, respectively. The sum of 4269 x 10^6 grams per day = 4706 tons per day.

[f] Reference 4 gives 0.6 x 10^6 grams per day for wastewater treatment sludges and 48.5 x 10^6 grams per day for raw water treatment sludge; sludge from surge tank bottoms air flotation skimmings and the FGD system and spent catalyst were listed but not quantified. The sum of 49 x 10^6 grams per day = 54 tons/day.

[g] Reference 4 gives 7713 x 10^6 grams per day or 8502 tons per day for coal pretreated wastes.

REFERENCES

U.S., Department of Energy, Assistant Secretary for Environment, Office of Technology Impacts. 1980a. *Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis.* Washington, D.C.: Department of Energy.

U.S., Department of Energy. 1980b. *Environmentally Based Siting Assessment for Synthetic Liquid Fuels Facilities*, DOE/EV/10287. Washington, D.C.: Department of Energy.

U.S., Department of Energy. 1980c. "Draft Appencix C of Final Environmental Impact Statement: SRC-II Demonstration Plant, Plant Design and Characterization of Effluents." N.p.

U.S., Environmental Protection Agency. 1979a. *Engineering Evaluation of Control Technology for the H-Coal and Exxon Donor Solvent Processes*, EPA 600/7-79/168. Washington, D.C.: Environmental Protection Agency.

U.S., Environmental Protection Agency. 1979b. *Environmental Assessment Report: Solvent Refined Coal Systems*, EPA 600/7-79-146. Washington, D.C.: Environmental Protection Agency.

APPENDIX B

TRANSPORTATION VALUE INDEX

APPENDIX B

TRANSPORTATION VALUE INDEX

The value of the hydrocarbon products of coal liquefaction for transportation purposes can be compared by use of an index that reflects the different values of products for transportation fuel. This "Transportation Efficiency" is a measure of the total Btu's of the product mix weighted to a high grade transportation fuel (unleaded premium gasoline) divided by the coal input. The transportation efficiency index is based on the Btu output of each product, weighted by a factor derived from the economic cost of that product compared to a high grade transportation fuel. For example, unleaded premium gasoline is weighted 1.0, and the more valuable fuels of butane and propane are weighted 1.08 and 1.07 respectively. Fuel oil is penalized, with a weighting of 0.56. The weighting factors ("value factor") and calculations are tabulated in Table B.1 and explained in more detail below. Although the weights are based on economic costs and prices, they are used to provide an approximation for the inefficiencies in upgrading coal-derived naphthas and fuel oils to transportation products. As compared to thermal efficiency, the transportation efficiencies are lower across the board, reflecting the relative cost to upgrade to transportation fuels. On this basis, Methanol and Methanol-to-Gasoline processes have the highest "Transportation Efficiency,"

TABLE B.1: PRODUCTS SUMMARY AND EFFICIENCIES (plant feed rate = 25,000 tons/day = 560,000 x 10^6 Btu/day)

Process	Product[b]	Quantity[d] Amount/Day	Thermal Value (10^6 Btu's)	Value Factor Transportation Preference	Transportation Value Equivalent (10^6 Btu's)	Total Heat Content (10^6 Btu's)	Thermal Efficiency (%)	Total Transportation Value (10^6 Btu's)	Transportation Efficiency (%)	Light Liquids Total (10^6 Btu's)	Efficiency Light Liquids (%)
DIRECT											
EDS						348,904	62.3	252,416	45.1	126,194	22.5
	Propane	3,270 bbl	10,464	1.08	11,301						
	Butane	3,500 bbl	12,250	1.07	13.108						
	Naphtha	19,900 bbl	103,480	.82	84,854						
	Fuel Oil	28,700 bbl	180,810	.56	101,254						
	C2-Gas	41.9 MMscf	41,900	1.00	41,900						
H-coal Syncrude						375,270	67.0	278,052	49.7	165,880	29.6
	Naphtha	31,900 bbl	165,880	.82	136,022						
	Fuel Oil	24,300 bbl	153,090	.56	85,730						
	Gas	56.3 MMscf	56,300	1.00	56,300						
SRC II						386,130	69.0	247,463	44.2	77,640	13.9
	LPG	5,500 bbl	22,000	.86	18,920						
	Naphtha	10,700 bbl	55,640	.82	45,625						
	Fuel Oil	45,300 bbl	285,390	.56	159,818						
	Gas	23.1 MMscf	23,100	1.00	23,100						

(continued)

TABLE B.1: (continued)

Process	Product^b	Quantity^d Amount/Day	Thermal Value (10^6 Btu's)	Value Factor Transportation Reference	Transportation Value Equivalent (10^6 Btu's)	Total Heat Content (10^6 Btu's)	Thermal Efficiency (%)	Total Transportation Value (10^6 Btu's)	Transportation Efficiency (%)	Light Liquids Total (10^6 Btu's)	Efficiency Light Liquids (%)
INDIRECT											
F-T						258,520	46.2	232,225	41.5	172,440	30.8
	Gasoline	18,200 bbl	91,000	.90	81,900						
	LPG	18,800 bbl	75,200	.86	64,672						
	No. 2 Oil	1,200 bbl	6,240	.82	5,117						
	Fuel Oil	2,000 bbl	12,600	.56	7,056						
	Med. Btu Gas	90.7 MMscf	36,280	1.00	36,280						
	C2-Gas	37.2 MMscf	37,200	1.00	37,200						
M-Gasoline						292,700	52.3	288,612	51.6	292,700	52.3
	Premium Gasoline	52,700 bbl	263,500	1.00	263,500						
	LPG	7,300 bbl	29,200	.86	25,112						
Methanol						317,520	56.7	305,726	54.6	317,520	56.7
	Methyl Fuel	113,400 bbl	294,840	.96	283,046						
	Methanol	8,400 bbl	22,680	1.00	22,680						

Source: Adapted from Rogers and Hill 1979.

[a] Data are standardized for on-site electric power generation using 10,000 Btu/kWh. Products are standardized for source coal with 11,200 Btu/lb-dry.

[b] Fuel oil means low sulfur boiler fuel comparable to No. 6 oil. Gases shown as MMscf = million standard cubic feet.

[c] See Table B-2 for heating value.

[d] See Table B-2 for value factor for transportation reference. This is approximated by economic cost of product relative to high grade gasoline.

and Fischer-Tropsch and SRC II, the worst. However Fischer-Tropsch suffers at a disadvantage in the comparison, because its naphthas and No. 2 fuel oil fractions are more suitable as transportation fuels than similar fractions from direct processes. Thus Fischer-Tropsch may not be distinguishable from other processes in about the 45 percent transportation efficiency range.

The product value technique was developed by the Engineering Societies Commission on Energy (ESCE)(Rogers and Hill 1979). This product value technique first calculates a price for a reference fuel (premium grade gasoline) and then fuel prices for other types of fuel are determined from the reference fuel price. Originally in the ESCE work, the purpose was to place an economic value on the products produced by various synfuel processes. However, here we have used these economic values as an estimate of the relative values as transportation fuels.

The value factor is the ratio of the Energy Price ($\$/10^6$ Btu) to the reference price premium gasoline (see Table B-2). The prices used were determined from mid-1978 published market prices (Rogers and Hill 1979). All liquid fuel products were subject to federal price controls to some degree in 1978 and this distorts the cost and value of transportation fuels, to some extent. Because natural gas prices are just now being released from price controls it was judged not possible to measure the value of natural gas. Because of its convenience and its high environmental advantages, the ESCE work assumed a market value for natural gas equivalent to premium gasoline on a Btu basis.

TABLE B.2: VALUE FACTORS FOR ENERGY PRODUCTS[a] (reference to premium gasoline)

Product	1978 Price ($)	Heating Value (10^6 Btu/bbl)	Energy Price ($/$10^6$ Btu)	Value Factor
Fuel Oil	12.35/bbl	6.3	1.95	.56
No. 2 Oil	14.92/bbl	5.2	2.87	.82
Naphtha	14.92/bbl	5.2	2.87	.82
LPG	12.04/bbl	4.0	3.01	.86
Gasoline	15.75/bbl	5.0	3.15	.90
Premium Gasoline[b]	17.50/bbl	5.0	3.50	1.00
Methanol[c]	17.50/bbl	2.7	3.50	1.00
Methyl Fuel[d]	17.50/bbl	2.6	3.36	.96
Butane	13.11/bbl	3.5	3.75	1.07
Propane	12.10/bbl	3.2	3.78	1.08
All Fuel Gases[e]	----	---	3.50	1.00

Source: Modified from Rogers and Hill 1979.

[a] No sales in 1978. Energy price assumed 10 percent less than fuel oil.

[b] Premium gasoline is reference fuel with value factor = 1.0.

[c] No significant market in 1978. Energy value assumed same as premium gasoline.

[d] No market in 1978. Energy price 4 percent below methanol for water content.

[e] Severe price regulation for natural gas in 1978. Energy value set at 1.00. See text.

The value factor approach to convert a range of coal conversion product Btu's to transportation equivalent value is based on the assumption that the cost of upgrading fuels is reflected in their market prices. It also assumes that future energy prices for particular products will maintain a fixed ratio to each other. Clearly this value factor is only an approximation distorted by market forces and price controls. However, it does provide a method to reflect the relative value of fuels which should approximate the cost of upgrading the poorer quality heavy fuels to lighter transportation grades among coal liquefaction products.

REFERENCES

Rogers, K. A., and R. F. Hill. 1979. Coal Conversion Comparisons, Final Report, Task 002, for the U.S. Department of Energy. Washington, D.C.: The Engineering Societies Commission on Energy, Inc.

APPENDIX C

POTENTIAL ACCIDENT SOURCES IN A COAL LIQUEFACTION PROCESS

APPENDIX C

POTENTIAL ACCIDENT SOURCES IN A COAL LIQUEFACTION PROCESS

A wide range of accidents can occur under coal liquefaction plant conditions. Table C.1 identifies the types of accidents in different sections of a direct liquefaction process referred to in Chapter V, Section B. Not included in the Table are the potential levels of environmental intrusion (effluents emissions, noise) that could result, or the extent of loss of life or property. For many of the coal liquefaction plant units, designs are conventional, in that they are based primarily on petroleum industry or coal fired utility experience.

Although these environments are hazardous, accident rates in the petroleum industry, for example, are substantially below the U.S. industry average as indicated in Chapter V.[1] Determination of the actual accident rates of coal liquefaction facilities will require several years of commercial plant operation. Accident rates may be similar to miscellaneous petroleum and coal products industries,[2] which are substantially higher than the U.S. industry average (see Chapter V).

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[1] For example, work days lost in the petroleum refining industry for 1977 were 45.5 per 100 full-time workers, compared to 82.3 for U.S. manufacturing industry.

[2] These industries experienced 237 work days lost per 100 full-time workers in 1977.

TABLE C.1: EXAMPLES OF HAZARDS IN COAL LIQUEFACTION (direct process)

System	Hazard	Accident	Result	Conventional (C) New Design (N)
		COAL PREPARATION		
Storage and handling	Coal	Fire	Release of smoke, CO, CO_2 and other coal combustion products	C (power plants)
Pulverizing and drying	Coal dust	Explosion	Large release of energy; fire with its release of coal combustion products; damage/injury to near-by equipment/personnel	C (power plants)
		REACTOR PROCESS		
Slurrying and pumping	Coal slurry	Piping, mix tank, or feed pump rupture	Release of process solvent, coal slurry, and fumes; minor fire; damage to equipment	N
Preheating and dissolution	Coal slurry and hydrogen	Slurry preheater tube rupture and backflow from the reactor	Fire; explosion; release of coal slurry, hydrogen, and reaction products (hydrocarbon vapor, liquids and solids, toxic fluids)	N
	Fuel gas or fuel oil	Explosion of furnace of slurry preheater or hydrogen preheater	Equipment damage; injury to personnel to personnel	N
	Reaction product	Coal dissolver rupture	Fire; explosion; release of toxic materials (H_2, CO, CH_4, H_2S, COS, NH_3, HCl, HCN)	N
	Recycle and make-up hydrogen	Tube rupture in hydrogen preheater	Fire; explosion	N

(continued)

TABLE C.1: (continued)

System	Hazard	Accident	Result	Conventional (C) New Design (N)
		HYDROGEN PRODUCTION		
Air separation	Liquid oxygen	Rupture of liquid oxygen vessels/heat exchangers	Formation of explosive gel in the presence of liquid hydrocarbons; creation of fire hazard; low-temperature hazard; oxygen-rich atmosphere	C
	Hydrocarbon contaminants	Explosion of vessels	Damage to equipment; injury; possible fire	C
	Liquid nitrogen	Rupture of liquid nitrogen vessels/heat exchangers	Vapor fog with possible hazardous concentration of nitrogen (asphyxiant)	C
Gasification	Ash/hydrocarbon slurry and/or coal slurry	Gasifier rupture or explosion	Fire or explosion; release of toxic material (CO, H_2S); injury; equipment damage	N
	Raw synthesis gas	Waste heat boiler rupture	Fire; explosion; release of toxic gas (CO, H_2S); injury; equipment damage	
Shift conversion	Raw synthesis gas	Shift reactor rupture	Release of pyrophoric catalyst and toxic gas; possible fire and explosion	This is a conventional, commercially available system.
		Rupture of heat recovery equipment	Release of toxic gas; high temperature steam; possible fire or explosion, damage to equipment; injury to personnel	
	Shift gas	Rupture of equipment	Release of hydrogen and toxic gases (H_2S, CO); fire; explosion	

(continued)

TABLE C.1: (continued)

System	Hazard	Accident	Result	Conventional (C) New Design (N)
		GAS RECYCLE SYSTEMS		
Acid gas removal	High pressure gas (H_2S, COS, CO_2 H_2, HCl, NH_3), hydrocarbon gases)	Rupture of container	Release of toxic process gases (H_2S, COS, HCl, NH_3); fire; explosion	C (refineries)
	Hydrocarbon solvents (DEA, MEA, butane)	Rupture of absorbers and strippers	Fire; explosion	
	Sour gas	Rupture of stripper	Release of toxic gases (H_2S, COS, HCl, NH_3)	
	Low-pressure gas	Rupture of absorber	Release of ethane-rich fuel gas and toxic sour gas; fire; explosion	
Hydrogen and LPG recovery	Hydrogen and hydrocarbons (liquid and vapor)	Rupture of equipment	Explosion; fire; release of hydrocarbons	C
Hydrogen compression	Hydrogen	Compressor rupture or massive seal failure	Release of asphyxiant; fire; explosion	C

(continued)

TABLE C.1: (continued)

System	Hazard	Accident	Result	Conventional (C) New Design (N)
		SULFUR REMOVAL		
Claus Units	Sour gas (CO_2, H_2S, NH_3)	Fire, explosion, rupture of equipment	Damage to equipment; release of toxic gas (H_2S, SO_2, NH_3); and possibly released reactor catalyst	C (refineries)
	Fuel and air in combusor	Explosion in start-up mode	Damage of equipment; injury to personnel	
Scot Units	Acid gas (H_2S and CO_2)	Rupture of stripper vessel	Release of toxic gas at low pressure	C (refineries)
	Acid gas and reducing gas	Rupture of hydrogenation reactor	Release of toxic/flammable gas mixture; possible fire and explosion	
		PRODUCT UPGRADING		
Hydrosulfurization	Naphtha/fuel oil feed	System leak or heater tube leak	Fire; explosion; release of naphtha and fuel oil	C (refineries)
	Hydrogen	Heater tube leak or compressor leak or rupture	Fire; explosion	
	Naphtha/fuel oil and hydrogen	Fixed bed reactor rupture or explosion	Fire; explosion; release of naphtha/fuel oil and catalyst	
	Catalyst	Catalyst handling system failure	Fire; release of reaction products and catalyst	
Acid gas stripper	Low-pressure gas	Rupture of stripper	Fire; explosion; release of toxic gas (H_2S, NH_3, CO)	
	Naphtha/fuel oil	Rupture of stripper	Fire; release of possibly carcinogenic material	

(continued)

TABLE C.1: (continued)

System	Hazard	Accident	Result	Conventional (C) New Design (N)
		SECONDARY PRODUCTS RECOVERY		
Ammonia recovery	Acid gas	Rupture of still or piping	Release of toxic gas (CO_2, H_2S, NH_3); possible explosion	This is a conventional, commercially available system
	Ammonia	Rupture of fractionator condensor, or pump	Release of toxic gas; possible explosion	
Tar acid recovery	Tars	Rupture of storage vessel	Release of carcinogenic liquids to immediate area; damage of equipment; fire	
	Stream	Rupture of reboiler	Explosion	
		UTILITIES AND STORAGE		
Storage	Product oils (naphtha, middle distillate, heavy oil)	Storage tank rupture, spills or leak, fire	Damage to equipment; personnel injury	The design of this system is based on existing commercial design and practice
	LPG	Storage tank rupture, spill or leak, fire	Damage to equipment; personnel injury; explosion	Potential for large explosion exists if superheated liquid is released to form rapidly expanding vapor cloud
	Process chemical (DEA, Selexol, caustic, MEA, sulfuric acid)	Storage tank rupture, spill or leak	Damage to equipment; personnel injury	

Source: Modified from U.S., DOE 1981a.

REFERENCES

U.S., Department of Energy (DOE). 1981a. Final Environmental Impact Statement: Solvent Refined Coal-II Demonstration Project, Fort Martin, Monongalia County, West Virginia, 2 vols. Washington, D.C.: DOE.

APPENDIX D

CONTACTS AND INFORMATION SOURCES

APPENDIX D

CONTACTS AND INFORMATION SOURCES

The following individuals were contacted and provided information, review comments or assistance in data development for this report. Identification of these individuals neither implies agreement with the data included in this report nor its interpretation. Data gathering also included attending the Electric Power Research Institute's Conference on Synthetic Fuels, October 13-16, 1980, and the Seventh National Conference on Energy and the Environment, November 30 to December 3, 1980. Interviews were also conducted with staff members at: U.S. Environmental Protection Agency, Denver, Colorado, and Washington, D.C.; Exxon Research and Development, Florham Park, New Jersey; Gulf Mineral Resources, Denver, Colorado; and Hydrocarbon Research, Lawrenceville, New Jersey. Contacts established at those visits are also included below.

A. GOVERNMENT AND FEDERAL LABORATORIES

NAME	ORGANIZATION	LOCATION
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C. PUBLIC AND PRIVATE RESEARCH/CONTRACTOR ORGANIZATIONS

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